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INDIANA UTILITY
REGULATORY COMMISSION

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND	)	
ELECTRIC COMPANY	)	
d/b/a VECTREN ENERGY	)	**CAUSE NO. 43839**
DELIVERY OF INDIANA, INC.	)	
(VECTREN SOUTH - ELECTRIC)	)	

DIRECT TESTIMONY

OF

DR. DALE E. SWAN - PUBLIC'S EXHIBIT NO. 13

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JUNE 25, 2010

EXETER

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TESTIMONY OF DR. DALE E. SWAN
CAUSE NO. 43839
VECTREN SOUTH-ELECTRIC

Q. Please state your name, occupation and address.

A. My name is Dale E. Swan. I am a senior economist and principal with Exeter Associates, Inc. Our offices are located at 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

Q. Dr. Swan, please summarize your professional qualifications.

A. I hold a B.S. degree in Business Administration from Ithaca College. I attended a master's program in economics at Tufts University, and I hold a Ph.D. in economics from the University of North Carolina at Chapel Hill. Prior to my consulting work, I served as Assistant and Associate Professor on the economics faculties of several colleges and universities. I also served as staff economist with the Federal Energy Administration and with the Arabian American Oil Company. For the last 35 years, I have consulted on matters primarily related to the electric utility industry, the last 30 years with Exeter. Much of my work over the last two decades has concentrated in the areas of long-term electric power supply planning and contract negotiations for large power users, and on electric utility cost allocation and rate design. For much of this period, I have directed Exeter's utility support services projects with the United States Department of Energy (DOE). As part of this work, I have been responsible for technical supervision of Exeter's participation in DOE interventions in numerous rate cases, and for the negotiation of technical aspects of power supply and facilities contracts.

A complete copy of my resume is provided as an attachment to my testimony.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified on a variety of topics relating to electric utilities in numerous proceedings before federal and state regulatory commissions, including the Indiana Utility Regulatory Commission ("IURC" or "Commission"). A complete list of the cases in which I have testified is provided as part of my resume.

I. Introduction

Q. Dr. Swan, what is the purpose of your testimony?

A. I have been asked by the Indiana Office of Utility Consumer Counselor (OUCC) to evaluate the reasonableness of the embedded, class cost-of-service study filed by Vectren Energy Delivery of Indiana, Inc. ("Vectren South-Electric" or "Company") in this case, and to provide alternative cost studies if that is appropriate. I have also been asked to recommend to the Commission an appropriate allocation of the allowed jurisdictional revenue requirement among the customer classes based on cost of service and other general rate design considerations, such as rate moderation or continuity. Finally, I have been asked to assess the Company's proposed rate design and recommend changes as appropriate.

The changes in the Company's class cost of service study that I recommend have been made by Dr. Emma Nicholson, who is filing companion testimony in this case. In addition, Dr. Nicholson addresses the statistical shortcomings of the Company's Zero Intercept Study, which provides the basis for the Company's Classification of a portion of line transformer costs as customer related.

Q. Do you provide schedules in support of your testimony?

A. Yes. I have attached Schedules DES-1 through DES-10 to my testimony.

Q. Were these schedules prepared by you or under your direct supervision?

A. Yes.

Q. Dr. Swan, please briefly describe your conclusions and recommendations.

A. As a result of my evaluation of the Company's embedded class cost of service study, its proposed spread of its requested total jurisdictional revenue increase and its rate design recommendations, I draw the following conclusions and make the following recommendations:

1. Vectren South-Electric's allocation of its generation and transmission plant-related costs violates the principle of cost causality and produces incorrect indications of class rates of return and cross subsidies.
2. A significant portion of Vectren South-Electric's generation and transmission plant-related costs are caused by planning decisions intended to reduce energy costs, and so should be allocated on the basis of energy use.
3. The Company incorrectly allocates no portion of its generation and transmission plant costs on energy use.
4. The Company's classification of a portion of line transformers as customer-related is conceptually incorrect and the statistical basis for the estimate is unreliable. Line transformers should be classified as 100 percent demand-related.
5. Uncollectible Accounts should be viewed as part of the general cost of doing business and should be allocated on the basis of class revenues rather than to the class of origin.
6. Customer Service and Information Expenses should be allocated on the basis of energy use at the meter rather than on the number of customers to

be consistent with the description of these expense items in the FERC Uniform System of Accounts.

7. The Commission should use, as the cost basis for determining the spread of the allowed change in jurisdictional revenues in this case, the OUCC Peak and Average (P&A) Cost of Service Study, which allocates an appropriate portion of generation and transmission plant-related costs on energy use.

8. If the Commission does not adopt the OUCC's P&A study, then it should use the OUCC's alternative 12-CP study as the cost basis for spreading the allowed change in total jurisdictional revenue among the classes.

9. The Commission should direct the Company to include Special Contract Customers as a separate customer class in the class cost of service study that it files in its next rate case to permit the Commission and others to evaluate the amount of the subsidy or discount that the Company proposes to offer to these customers.

10. The Commission should temper its use of equalizing class rates of return as the objective of the class revenue spread given the greater risks associated with serving large industrial customers over the business cycle.

11. In view of the dramatic reduction in industrial usage and the resulting shift in cost responsibilities to classes of small, low load-factor customers in this case, the Commission should direct the Company to recover the allowed revenue increase in this proceeding through an equal, across-the-board percentage increase for all customer classes.

12. If the Commission allows any part of the Company's proposed step 2 increase, it should allocated among the classes on the basis of energy use at generator to recognize that dense pack investments in the Brown Units 1 and 2 will be made to reduce fuel costs and Environmental Emission Allowances, both directly related to the production of energy by these two generating units.

13. The Company's overall approach to the redesign of its rates is to shift revenue recovery from energy charges to up-front facilities charges and to demand charges. This has the effect of shifting risk from the Company to its customers. The Commission should direct the Company to temper this shift to facilities and demand charges.

14. The Commission should direct the Company to retain the existing customer facilities charges for customers taking service under Rate Schedules RS – Standard, RS – Transitional, and Small General Service. If an increase is permitted to these charges it should be limited to the overall percentage increase in jurisdictional rate revenues that the Commission allows at the close of this case.

15. The Commission should order the Company to tie the grandfathering of the lower tail block rate for residential heating service to the residence rather than to the customer, to ensure that customers who buy existing residences will not face unexpected rate shocks. In addition, the Company should be directed to phase out the special heating provisions over a 10-year period.

II. Allocation of Costs in Vectren South-Electric's Cost of Service Study

Q. Please describe the attributes of a class cost of service study and explain what such a study is supposed to accomplish.

A. Average, embedded, historic class cost of service studies of the type performed by Company witness Kerry A. Heid are performed in an attempt to determine the share of total costs that is incurred to provide service to each class of customers. Such studies are referred to as average, embedded, historic cost studies because they attempt to directly assign or allocate to each customer class, actual book plant and related costs, adjusted to test year levels as authorized by the Commission. They are also referred to as "fully allocated" costs because these studies require that 100 percent of the allowed total jurisdictional costs of service be allocated among the various classes. This is done by determining the average costs of the various components of service (the total cost of the component divided by the units of service for that component), and then by allocating these component costs to each of the classes, based on each class' service units that have caused that cost. This is a fundamental aspect of an embedded cost of service study – that is, costs should be assigned or allocated to classes on the basis of the factors that caused each of those costs to be incurred.

The costs are first functionalized into broad categories, such as production costs, transmission costs and distribution costs. These costs may be further broken down by voltage delivery level and other sub-functions may be identified. Costs are then classified as to whether they are demand-related, energy-related, customer-related or related to some other factor, such as labor costs or revenue. Finally, the costs are allocated among the customer classes on the basis of the most appropriate measure of demand, energy or customers, in proportion to each class' share of the various allocation measures.

Q. What cost allocations in the Company's class cost of service study are of particular concern in this case?

A. Of particular concern is the way in which generation and transmission capital costs have been allocated in the Company's study. Specifically, these costs have largely been allocated on a peak demand basis, with no responsibility being assigned to energy. I also take issue with the Company's allocation of line transformers, Uncollectible Accounts and Customer Service and Information Expense.

Q. Please explain the basis upon which Vectren South-Electric has allocated its generation plant and related O&M costs.

A. The Company has classified 100 percent of its production plant costs as demand related and has allocated these costs to customer classes based on each class' share of the Company's coincident peak demand in four summer months (June through September - "4 CP"). Mr. Heid provides the following explanation of why all of these production (as well as transmission) plant costs are classified as demand related:

> Most capital costs are demand-related because the investment in facilities is related to the size of the facility, and facilities are sized to provide service under peak load conditions. (Petitioner's Exhibit KAH-1, p. 6)

Q. How has the Company allocated transmission plant costs?

A. The Company has classified all of its transmission plant costs as 100 percent demand related and has also allocated those costs on the basis of class contributions to the average of the four monthly summer coincident peaks ("4 CP"). The classification as

100 percent demand-related and the allocation on the 4 CP vector are based on the same logic as generation plant.

Q. How has the Company classified and allocated production plant-related and transmission plant-related O&M costs?

A. The Company conducted a special study of the proper classification of production-related O&M costs, and concluded that approximately 24 percent of Total Production Expenses (other than FAC-fuel costs) should be classified as energy related. According to Mr. Jochum (Petitioner Exhibit No. RGJ-1, p. 10), these expenses relate to chemicals associated with the operation of environmental control equipment, coal combustion byproduct disposal, fuel handling, and boiler water chemicals. These energy-related variable production costs have been allocated among the classes based on energy at generator. The demand-related portion of these expenses has been allocated on the 4 CP vector at generation. All of the transmission- and sub-transmission-related O&M costs have been classified as demand-related and allocated on the 4 CP at generation vector.

III. The Proper Allocation of Generation and Transmission Plant Costs

Q. Do you agree with the Company's classification and allocation of most production plant related and all transmission plant related costs as 100 percent peak demand related?

A. No. A cost study should classify and allocate costs among customer classes on the basis of the factors that caused those costs to be incurred, and Vectren South-Electric's total production and transmission plant investment costs have not been caused solely by the peak demands of its customers. A significant portion of those investment costs have been directly caused by the need to meet the energy requirements of the Company's customers, and so a commensurate portion of the investment costs and the associated plant-related O&M costs should be allocated on the basis of class energy usage.

Q. Please explain why a significant portion of generation investment costs should be properly classified as energy related and allocated on class energy usage.

A. Generation capacity planning by utilities, including Vectren South-Electric, is conducted in order to meet reliability requirements as well as the sustained energy demands of its customers at the least possible cost. That means that sufficient generation capacity must be installed or purchased to meet the system peak demands plus the planning reserve requirement. Thus, the system peak demands are clearly responsible for the <u>amount</u> of generation capacity that Vectren South-Electric has installed or purchased. However, the total <u>cost</u> of that capacity is <u>not</u> directly caused by the magnitude of the system peak demands. It would be inconsistent with rational economic planning to base generation plant investment decisions solely on the basis of meeting peak demands. A simple example will show how the Company's current and planned mix of generation capacity would differ considerably if its generation investment decisions were based only on meeting peak demands. If Vectren South-Electric had planned its generation mix only to meet the four highest monthly peak demands over the course of the year at the lowest possible cost, it would have done so by building only peaking plants. This is because peaking generation facilities are more economical for meeting peak demands than for meeting sustained demands for electricity. The capital cost of peaking facilities is relatively low – generally the lowest of all possible generation alternatives. On the other hand, the operating cost of peaking plants is generally the highest of all possible alternatives, due to much higher heat rates and more expensive fuel as compared to intermediate or baseload units. However, the high variable cost of peaking units is inconsequential if the only objective is to meet the load during the four hours of the Company's annual four coincident peaks, since those expensive operating costs would only be experienced for four hours during the year.

Q. Then why does a company such as Vectren South-Electric build baseload generation plant?

A. Vectren South-Electric does not have to plan for generation plant only to meet the four highest hourly loads during the year. It has sustained demands for all 8,760 hours during the year, and Vectren South-Electric, like all utilities, plans its generation mix to minimize the cost of meeting, not just those four highest hourly demands, but the sum of demands year round. To do that, the Company has invested in significant baseload generation capacity. Baseload plants have significantly higher capital costs, but generally significantly lower operating costs than do peaking plants. The much lower operating costs result from their ability to use less expensive fuels and to convert those fuels to electricity at lower heat rates. The question then is, what must occur to warrant the higher investment cost per kW of baseload plant as compared to peaking plant. The answer, of course, is that these higher capital cost baseload units must be operated sufficient hours during the year to result in operating cost savings sufficient to offset the higher capital costs. That means that these generating units are added to meet sustained demands of customers. Saying it slightly differently, it means that these higher capital costs are incurred to result in energy savings. Thus, the difference between the capital cost of a baseload unit and the capital cost of a peaker is incurred to meet energy requirements at a lower total cost.

Q. Can you provide a simple numerical example of this trade-off?

A. Yes. Let's consider a simplified world where there are only two types of generating plants for the Company to consider – baseload plants and peaking plants. Let us further assume that the operating cost per kWh is $0.025 for a baseload plant with an installed cost of $3,000 per kW, and $0.09/kWh for a peaking plant with an installed cost of $900 per kW. For sake of simplicity, let us assume that the annual carrying charge rate for both plants is 15 percent. Thus, the annual capital cost of the baseload unit is $450 per kW, and the annual capital cost of the peaker is $135 per kW. Building the baseload plant will result in a higher annual capital cost of $315 per kW. It will prove economic to build the baseload plant rather than the peaker as long as the baseload plant can be run for at least 4,846 hours a year, or at an annual capacity factor of 55 percent. This breakeven point is determined by dividing the additional capital costs of the baseload unit by the differential in operating costs of $0.065/kWh. Savings are realized for every hour beyond 4,846 that the baseload plant is operated during the year. Clearly the difference between the $3,000 per kW and $900 per kW has been invested not to meet peak demand, but to reduce the cost of energy on the system in the process of minimizing total costs.

Q. Can you show graphically how this relationship works?

A. Yes. The breakeven point can also be shown with a simple diagram, as presented below in Figure 1. The two lines represent the total annual costs at varying levels of annual generation for a 1 kW peaking unit and a 1 kW baseload unit. Total annual cost is shown on the vertical axis and total hours of operation per year are shown on the horizontal axis, which is also the total kWh produced since we are concerned with two 1 kW units. The y-intercept of each line shows the annual capital cost of each unit, which is significantly higher for the baseload unit. The slope of each line shows the variable cost (primarily fuel) of producing an additional kWh, which is much higher (steeper) for the peaker than for the baseload unit. The intersection of the two lines is the break-even point, or the number of hours the baseload unit must be operated each year to warrant its higher capital cost. The difference between the two lines after the break-even point measures the annual total cost savings at each level of operation from building and operating the baseload unit as compared to the peaker. The cost savings are realized through the lower operating costs (i.e., energy savings) of the baseload unit compared to the peaker.

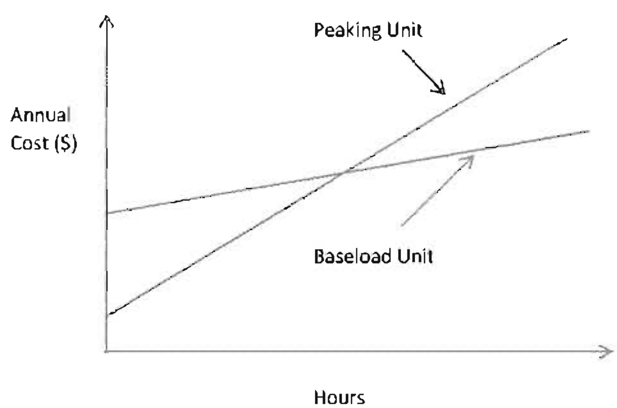

Figure 1

Q. Does Vectren South-Electric experience sustained electric demands that would warrant investment in baseload units?

A. Yes. We obtained the Company's hourly loads for 2008 and 2009 in response to OUCC Request 1-07 and these load data were used to construct Load Duration Curves (LDCs) for those years, which are provided in Figure 2. Those LDCs show that the minimum load was approximately 387 MW in 2008, or approximately one-third of the annual 2008 peak load of 1,168 MW. In 2009, the minimum load was 386 MW, or 34 percent of the annual peak of 1,148 MW. In other words, loads were approximately one-third of the annual peak for all 8,760 hours during the year. In 2008, the average load was 676 MW, or approximately 58 percent of the annual peak load, which is referred to as the annual Load Factor. The annual Load Factor is a measure of the extent to which demand is sustained over the course of a year. In 2009, the average load was 643 MW or approximately 56 percent of the annual peak. The LDCs show Vectren South-Electric's annual load shape and they make it clear that the Company has significant sustained demands over the course of the year. Vectren South-Electric must plan its generation mix not only to meet its peak demands, but to meet those sustained loads at minimum total cost, and it has done that by installing an appropriate mix of the several types of generation capacity – baseload, intermediate and peaking.

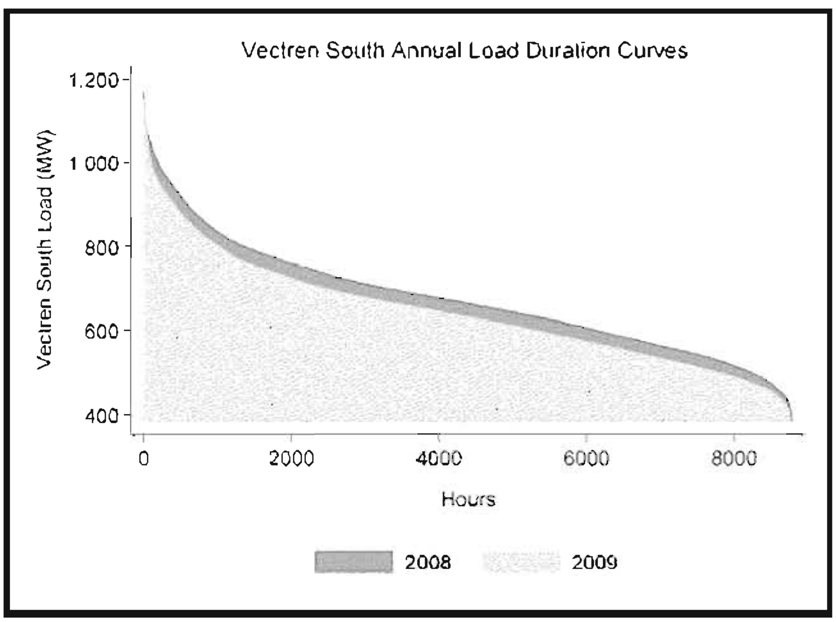

Figure 2

Q. How has Vectren South-Electric planned its mix of generation capacity?

A. This is best explained by reference to Vectren South-Electric's Integrated Resource Plans (IRPs). The Company's IRPs provide blueprints for how it expects to expand its generation capacity over the intermediate to long term, and explain the factors that caused the Company to build the generation plants that it did. We obtained from the Company its most recent IRP, which it filed for calendar year 2009. (Response to OUCC Data Request 1-02) In addition, we obtained copies of the IRPs that the Company filed for calendar years 1991 and 2001 in response to OUCC Data Request 10-09. The 2009 IRP provides us with an explanation of how the Company is currently planning its generation system and the factors that would cause those capital costs to be incurred. The 1991 and 2001 IRPs provide us with an understanding of how the Company planned its generation system over the last two decades, and so the factors that caused the incurrence of capital costs that make up a portion of today's embedded costs of generation rate base.

Q. What does one learn from reviewing the 2009 IRP regarding the factors that currently cause generation capital costs to be incurred?

A. To begin, the Company sets forth the purpose of the IRP as developing "the optimal strategy for adding the resources necessary to reliably meet the future demand requirements of Vectren's electric customers."[1] The reliability criterion used by the Company is to maintain a minimum 15 percent planning reserve margin.[2] The Company's plan goes on to state that, "The optimal plan is defined as the best possible combination of resource additions that results in reliable service at the lowest

[1] "2009 Integrated Resource Plan," p. 152.
[2] Id., p. 153.

cost to customers over the twenty year planning horizon."[3] The lowest cost among the several possible combinations of resources considered is equated to the minimization of the present value of the expected stream of revenue requirements associated with each combination of resources.[4] Given the significant reductions in demand that the Company has realized in the last few years, it concluded that it should not install "any additional generation on its system," nor enter into any "additional purchase power agreements during the planning period [through 2029]."[5] In fact, given the expected reduction in future loads, the Company projected "system reserve margins in excess of 27% throughout the 20 year planning period."[6]

Q. Was this same approach to planning generation expansion taken in the preparation of its earlier IRPs?

A. Yes. The approach was essentially the same in 1991 and 2001. The 1991 IRP stated that its objective was to develop a generation expansion plan that resulted in the "lowest energy costs to SIGECO's customers in the long run," or "an expansion plan with the lowest present worth of total annual revenue requirements."[7] Based on its then current forecast of annual energy growth of 2.03 percent and the growth of peak demand of 1.74 percent,[8] the Company concluded that its long-term capacity expansion plan should include the "construction of combustion turbines in 2004 and 2010, and baseload pulverized coal plants in 1999 and 2008."[9]

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[3] Id., p. 152.
[4] Id.
[5] Id., p. 12.
[6] Id., p. 11.
[7] "Integrated Resource Plan: 1991," Southern Indiana Gas and Electric Company, February 1991, p. VII-1.
[8] Id., p. ES-2.
[9] Id., p. ES-4.

The Company changed its view of the future by the time its 2001 IRP was prepared. The forecasted rate of growth of its energy requirements had fallen to an approximate 1.0 percent a year, and its forecast of peak demand had been reduced to grow from 1,211 MW in 2000 to 1,532 MW in 2020, an average annual rate of growth of 1.16 percent.[10] The overall approach to planning for generation capacity was essentially the same, however. The objectives were more or less the same and included providing "all customers with a reliable supply of energy," and being "the low cost provider of energy in southern Indiana."[11] Given that reliability requirements were met, the critical criterion for selecting among the several resource combinations remained the "lowest total present value of revenue requirements" and, as the IRP states, "These annual revenue requirements consist of both annual fixed costs (carrying charges) associated with existing facilities and new capital investments, as well as the variable costs (production costs) associated with operating the generating system."[12] On the basis of its analysis of loads and the costs associated with different resource options, the Company concluded that its "least cost resource plan calls for new capacity additions of 73 MW combustion turbines in each of the years 2002 and 2004, a 10 MW peaking purchase in 2003, a 135 MW combined cycle unit in 2007, and various upgrades of existing units in 2015, 2016, 2018 and 2020."[13]

Q. What is learned from this review of Vectren South-Electric's current and past IRPs over the last two decades?

[10] "2001 Integrated Resource Plan (Revised) for Southern Indiana Gas and Electric Company," April 18, 2002, pp. 7, 33.
[11] Id., pp. 6-7.
[12] Id., pp.9-10.
[13] Id., p. 95.

A. It is clear from reviewing these IRPs that the Company is constantly revising its generation resource mix as its load forecasts change and as changes occur in generation technologies which are accompanied by changes in the relative capital and operating costs of competing generation resource options. This is as it should be and it constitutes good resource planning. What is also apparent is that the Company has regularly assessed the relative operating and capital costs associated with different generating technologies to determine how to minimize the expected stream of revenue requirements, and has chosen a capacity expansion path based in large part on those relative costs. In short, the Company's IRPs are essentially a translation of the simple trade-off analysis that is presented in Figure 1 into a comprehensive analysis of the factors that largely drive the selection of which generating units to add to the system. Fundamentally, that is the trade-off between generators with lower capital costs per kW and higher operating costs per kWh, and generators with higher capital costs per kW and lower operating costs per kWh. It is this trade-off that has guided the Company's selection of the generation plant that it has decided to construct and the underlying factors of capital costs and energy savings are what have caused the Company to decide on the configuration of the generation fleet that currently makes up its generation rate base.

Q. After reviewing Vectren South-Electric's IRPs, exactly how has it planned to meet its sustained energy demands throughout the year?

A. It has planned its generation mix to meet, at least cost, not only the peak loads which occur for only a relatively few hours during the year, but also the sustained loads that will last for between, say, 4,000 hours to 8,760 hours each year. That means the Company has selected a mix of generation plant that includes a significant amount of baseload capacity that operates at high annual capacity factors to meet these sustained loads. Schedule DES-1 demonstrates this fact.

Schedule DES-1 is developed from information provided by the Company in response to OUCC Request 2-5. This Schedule provides for each of the Company's generation units the net capacity in MW, the fuel type, whether the unit is operated as a baseload or peaking unit, the average annual generation for the years 2007 through 2009, and the average number of hours per year each unit was connected to load for the period 2007 through 2009. Several aspects of this schedule are striking. First, six of the twelve generating units are baseload units and they account for over 77 percent of the total net generation capacity. The six peaking units account for only 295 MW of net generating capacity, or approximately 23 percent of the total.

The other thing that is striking is that, over the period 2007 through 2009, all of the baseload plants were connected to load in excess of 6,500 hours a year, for an average over the three-year period of 7,491 hours. On the other hand, during this same period, the Company's peaking units were connected to load an average of just 169 hours. The Company's baseload units accounted for 99.2 percent of total generation during this period, while its peaking units were responsible for only 0.8 percent of total generation.

Q. What do you conclude from this information?

A. Vectren South-Electric maintains a diverse mix of generating capacity, but the lion's share of that capacity is baseload generation that is connected to load for an average of over 85 percent of the hours in the year. This more expensive baseload capacity has clearly been installed in order to meet sustained demands over the year – that is, the energy requirements of the Company. Vectren South-Electric's peaking units make up 22 percent of total capacity, have been connected to load an average of only about 169 hours a year during typical operation, or only about 2 percent of the total annual hours, and have produced only 0.8 percent of total energy output. It is equally clear that these peaking facilities, with significantly lower capital costs, were installed primarily to meet peak demands on the system that occur for no more than a few hundred hours each year. While the total amount of Vectren South-Electric generation capacity has been planned to meet peak demands, the cost of that capacity is only partly caused by the system peak demands and significantly caused by the need to meet sustained energy demands throughout the year at lower operating costs.

Q. Given these observations, is it reasonable for the Company to allocate total generation plant and related costs only on the basis of four peak hour demands during the year?

A. No. Vectren South-Electric's $1.3 billion invested in generation plant reflects the Company's baseload plant requirements as well as its peaking plant requirements. The Company's response to OUCC 1-05 shows that baseload coal plants comprise 92 percent of the total original installed cost of production plant. It would be incorrect to find that the Company's total generation investment was caused only by its need to meet peak demands during the year. The more expensive baseload steam plant, which comprises the bulk of Vectren South-Electric's generation capacity, has been installed only because it can provide fuel and operating cost savings sufficient to overcome the higher capital costs of these units. Thus, only a portion of the Company's generation plant and related costs relate to the need to meet peak demands. A significant portion of those generation plant costs relate to the sustained energy demands that caused baseload plant, not peaking plant, to be included in and to dominate the Company's generation plant mix.

Q. How do you respond to the argument that, if you have enough plant to meet peak loads, then you automatically have enough capacity to meet all lesser demands, and so it is only peak demands and the need to service them that cause all generation plant costs?

A. If peak demands were the only demands that had to be met, then only peaking plants would be required, and the total generation plant investment would be significantly lower. This again goes back to the observation that peak demands do determine the total amount (Megawatts) of generation plant that is required, but peak demands do <u>not</u> determine the total <u>cost</u> of that plant. The additional generation investment costs result from the decision to invest in much more expensive baseload plant in order to reduce the cost of meeting the sustained energy demands of customers through fuel and operating cost savings. Thus, peak loads do not cause all generation plant costs and it would be wrong to allocate Vectren South-Electric's generation facilities on peak demands only.

Q. Can you provide an example of how costs are misallocated when all generation plant and related costs are allocated on a peak demand basis only?

A. Yes. The 4-CP method utilized in the Company's study allocates all generation plant cost, including the high-cost baseload plant, on the basis of each class' contribution to four monthly system coincident peak demands. Under this approach the Residential Class is allocated 48 percent of total generation costs, including baseload plant. (See Petitioner's Exhibit No. KAH-S2, Schedule 3, page 1, Input Allocator No. 4.) The major benefit of baseload plant operation is the ability to reduce energy costs by using lower cost fuels and converting that fuel to electric energy at lower heat rates. The energy cost savings are allocated to customer classes on the basis of their relative energy usage at source. Since residential customers are generally relatively low load factor customers, they use relatively less energy per kW of their contribution to the system coincident peak demands. Specifically, under the Company's study, the Residential class receives only 37.0 percent of the energy savings that are realized by the installation of baseload units, rather than peaking units, to meet sustained energy demands. (Petitioner's Exhibit No. KAH-S2, Schedule 3, page 1, Input Allocator No. 1.) Thus, the residential class would be caused to pay for 48 percent of the cost of the plant that generates the energy savings but is only allocated 37 percent of the resulting savings. This amounts to a clear mis-match of the costs of and the benefits associated with the construction and operation of baseload generation plants.

Q. Is there an allocation method that recognizes the importance of both peak demands and sustained demands being responsible for Vectren South-Electric's generation facilities costs?

A. Yes. I recommend a method that allocates a portion of plant and related expenses on the basis of class contributions to the relevant measure of system coincident peak demand, and the remainder on the basis of class energy use at source. This is sometimes referred to as a Peak and Average ("P&A") method, since annual energy divided by the number of hours in a year yields the average demand. The average demand portion of the P&A allocator recognizes sustained demands; the peak portion of the P&A allocator recognizes that peak demands are also responsible for a portion of a utility's generation plant related costs.

Q. How does one determine the share of these costs that should be allocated on peak demand and the share that should be allocated on average demand or energy?

A. There are several ways to make this split. One approach is to determine what the installed cost of total generation plant would have been had only peaking generation been installed. Expressing that cost as a percentage of total generation installed costs provides the share of production plant investment costs that should be allocated on some appropriate measure of system coincident peak demand. The remaining share is the portion of total production investment costs that has been incurred to meet year-round energy requirements at minimum total costs. This calculation can be made using actual installed costs. The problem with this approach is that the on-line dates of generating units may vary widely. For example, Vectren South-Electric's 2008 FERC Form 1 Report shows that the installation of its generation fleet stretched from 1963 (Northeast 1 CT) to 2002 (Brown 4 CT). This wide variation in on-line dates tends to distort the calculation of the portion of these costs incurred solely to meet peak demands unless the data are massaged to account for the inflation in capital costs over this ninety-year period. Alternatively, one can take a more forward-looking approach and value each type of plant by the investment cost per kW that Vectren South-Electric has used when evaluating its various capacity expansion options.

Q. Have you developed this type of calculation for Vectren South-Electric?

A. Yes. I have made this calculation for Vectren South-Electric based on both actual installed costs and on the forward-looking replacement costs of each type of capacity. These calculations are presented in Schedule DES-2.

Q. Please describe Schedule DES-2.

A. Schedule DES-2 calculates the total installed capacity for each type of generation unit that the Company currently has in its fleet: peaking units, base load coal-fired units and the Blackfoot land-fill gas unit. On page 1 of that exhibit I have calculated the energy/demand split based on original installed costs. In column (3) is shown the original installed cost for each unit in nominal dollars (dollars in the year the unit was placed on line). In Column (4) is provided the original installed cost escalated to 2009 dollars, using the Producer Price Index. Based on 2009 dollars, the exhibit shows that, had only peaking plant been installed, the total installed cost of the generation fleet would have been approximately 21 percent of the actual cost, including the cost of baseload capacity. If nominal dollars are used in the calculation the total fleet would have cost 31 percent of the actual total cost if only peaking plant had been installed. On the basis of this analysis, between 21 percent and 31 percent of the cost of generation plant should be allocated on the appropriate measure of peak demand, and the remainder (between 71 percent and 81 percent) should be allocated on energy use at generator.

On page 2 is shown the calculation of the energy/demand split based on replacement costs. The total amount of installed capacity for each unit type is valued by the cost of a new unit of the same type. These replacement costs were obtained in Vectren South-Electric's 2009 Integrated Resource Plan, and were used in the evaluation of the Company's alternative capacity expansion plans. In the last column of on page 2 I have calculated what the total cost of the Company's generation fleet would be if all of its capacity had taken the form of peaking units, intended only to meet the peak demands on the system. That amount is $1.55 billion, which constitutes approximately 45 percent of the total cost of Vectren South-Electric's generation fleet of $3.46 billion, valued at replacement costs. On the basis of this analysis, approximately 55 percent of production plant and associated O&M expenses should be allocated on energy and the remaining 45 percent should be allocated on the basis of class contributions to the relevant measure of system peak demand.

Q. Is there another method by which to determine the split between demand-related and energy-related allocations of production plant and associated O&M expenses?

A. Yes. Another common way to determine this split is to set the proportion of plant allocated on average demand on the basis of the system load factor. Thus, if the load factor were 0.54, then 54 percent of the generation plant and plant related costs would be allocated on energy, while the remaining 46 percent of these costs would be allocated on peak demands. Similarly, if the load factor were 0.60, then 60 percent of the generation plant related costs would be allocated on energy and the remainder on peak demands. The load factor percentage reflects the relationship between average demand and peak demand, and using the load factor split explicitly recognizes the need to allocate a substantial portion of electric generating plant and related costs on average demands. As the load factor increases, and baseload plant becomes more and more the plant of choice, the amount of plant allocated on average demand increases.

Q. What is the appropriate load factor share for Vectren South-Electric?

A. The annual load factors calculated in Figure 2 for Vectren South-Electric are 57.9 percent in 2008 and 56.0 percent in 2009. Using the load data provided in the Company's 2008 FERC Form No. 1 (page 401b), which includes sales for resale, yields an annual load factor of about 67 percent. The Company's 2009 Integrated Resource Plan shows forecasted load factors hovering around 56 percent for the next several years (p. 41).

Q. Based on both your analysis in Schedule DES-2 and the evaluation of Vectren South-Electric's load factor, what portion of production plant costs do you propose to allocate on energy, and what portion on a measure of peak demand?

A. Based on both of these analyses, I recommend that 55 percent of production plant costs be allocated on class energy use, and the remaining 45 percent be allocated on each class' contribution to the appropriate measure of peak demand.

Q. Dr. Swan, how do you propose that the portion of generation plant and related costs assigned to peak demands be allocated?

A. Once the proper classification of the energy portion of production costs is determined, the demand-related portion of these costs should be allocated on a fairly narrow definition of peak demand. The Company has made a reasonable case for measuring peak demand by the class shares of the average of the four highest summer monthly system coincident peaks -- the 4-CP method. Thus, I propose to use that allocator to allocate the peak demand related portion of generation plant costs among the customer classes. But, it should be understood that my endorsement of the 4-CP method is limited to the allocation of <u>only</u> the demand-related portion of costs in the P&A method. In my view the 4-CP measure is too narrow a definition of peak demand to be used to allocate the total of production plant and related expenses.

Q. Dr. Swan, earlier you indicated you do not agree with the Company's decision to allocate 100 percent of transmission plant costs on peak demands, and that a significant portion of these costs should also be allocated on energy use. Please explain.

A. Vectren South-Electric's $248 million investment in transmission plant has resulted in a transmission system that is essential to the Company's reliance on large, fuel efficient, baseload generating plants that are sometimes located at some distance from load centers. Vectren South-Electric could not deliver its baseload generation of electricity, which is essential at all times during the year, without its transmission system. In short, the Company's decision to minimize its total cost of service by relying heavily on baseload generation has necessitated its significant investment in transmission facilities. Thus, the Company's reliance on transmission facilities is "caused" in large part by its decision to rely heavily on large, lower fuel-cost baseload generation rather than to rely on smaller, higher fuel-cost peaking generation.

Q. Can you explain further how transmission investment is largely related to energy use?

A. Consider the utility's decision whether or not to invest in transmission facilities. A utility could meet its generation capacity requirements by building more and smaller peaking generating plants close to its load centers and tying these smaller plants into the lower voltage delivery system in the localities that make up the load centers. This approach would have significantly reduced the need to build transmission lines. Alternatively, the utility could build large, baseload generation plants at sites at some distance from some or all of its load centers, but nearer low-cost fuel supplies or transportation terminals, and transmit this power to its load centers at high voltages to minimize losses. It can also use those high voltage transmission lines to import less expensive energy from neighboring systems. It would take the latter course only if the operating (mostly fuel) savings of the large, remote, baseload units or purchases from neighboring systems were sufficient to more than offset the additional capital costs of the required transmission lines. Most utilities, including Vectren South-Electric, have taken this latter course, and consequently a significant portion of the investment in transmission lines has, in fact, been made largely to lower energy costs and not to meet peak demands.

Q. Is there any evidence that Vectren South – Electric has specifically planned its transmission system with an eye toward the substitution for generation capacity costs or that bulk transmission will be required as a compliment to distant baseload generation?

A. Yes. In its 2001 IRP the Company stated that, "If new peaking capacity is added, generation site selection will include analysis of the potential to use the generation project to offset transmission upgrades that would otherwise be needed." It goes on to state that, "If new generation is acquired outside the SIGECO system, new 138 kV and 161 kV interconnections would be needed. 345 kV projects would also be investigated but would require involvement of other utilities."[14] This latter identical statement was also made in the Company's 2009 IRP.[15]

Q. How do you propose that investment in transmission plant be allocated among the classes?

A. Vectren South-Electric's transmission costs are incurred in part to provide for the delivery of baseload electricity at all times when a baseload plant is generating electricity. However, the Company's transmission investment is larger than it would be if it only had to meet its customers' average demands. Therefore, a portion of Vectren South-Electric's transmission costs relate to meeting its customers' energy demands, and a portion relates to meeting peak demands. The Peak and Average allocation method fairly and reasonably allocates Vectren South-Electric's transmission costs on an energy basis and on a peak demand basis.

Q. How should production- and transmission-related O&M costs be allocated among the classes?

A. The Company has conducted a special study which determined that $24 million of Steam Power Generation Expenses is clearly related to the provision of energy, and

[14] Op.cit., 2001 IRP, pp. 109-110.
[15] Op. cit., 2009 IRP, p. 148.

has proposed that these expenses be allocated on energy use at generator. I agree. The remaining Production Demand related O&M costs and all of Transmission O&M costs should follow the allocation of plant. That means that 45 percent of those costs will be allocated on peak demand and 55 percent will be allocated on energy use at generator under my P&A methodology.

IV. The Treatment of Upstream Distribution Plant

Q. How has the Company classified and allocated distribution plant?

A. After functionalizing distribution plant upstream of meters and service drops into primary distribution and secondary distribution, the Company has classified 100 percent of primary distribution plant as demand-related. It has allocated those costs on the average of class shares of non-coincident class peaks at primary distribution voltage and class shares of the sum of individual customer peak demands at primary voltage. I believe this is a reasonable way to classify and allocate primary distribution plant because this method recognizes that this plant has been installed to meet local neighborhood peaks, and as one moves further upstream from customers' loads there is greater demand diversity on the system. Meters and service drops are classified and allocated based on special studies of meters and services that largely reflect the number of customers and also the differential costs of meters and services that are required to serve the different classes. I find this treatment of meters and services reasonable because there is generally a one-to-one mapping between the number of customers and the number of services and meters.

Secondary distribution plant, other than line transformers, is classified as 100 percent demand-related. Line transformers are classified as partly demand-related and partly customer-related. The demand related portion of secondary distribution plant is classified on the basis of class shares of the sum of individual customer maximum demands. This is a reasonable allocator since it recognizes that the benefits of diversity are reduced as one moves closer to customer loads. The customer-related portion of line transformers is determined with a zero intercept study, and these costs are allocated among the classes on the basis of the average number of secondary customers.

Q. Do you agree with the Company's classification of a significant portion of line transformers as customer-related?

A. No. The effect of the Company's treatment is to allocate $22.2 million, or 37 percent, of upstream secondary distribution plant on the number of customers, which is clearly detrimental to the classes of small customers. I find Mr. Heid's treatment of these costs unsatisfactory on both a conceptual and implementation level.

Q. Please explain your conceptual objection to Mr. Heid's classification of a significant portion of the costs of line transformers as customer-related.

A. The general rationale for arguing that some portion of upstream distribution plant costs are customer-related is that a hypothetical portion of these costs is incurred simply to connect customers to the system without providing any actual electric capacity or energy. Mr. Heid attempts to estimate this hypothetical portion of line transformer costs as the constant term in a statistical regression equation relating the cost of transformers to the capacity of those transformers. In fact, the cost of upstream distribution plant is incurred in order to meet the coincident loads of the customers that it serves and their sustained energy demands throughout the year. The size and costs of the required plant are a function of the amount of diversity of customers' loads that must be served from this plant, as well as the expected future coincident loads that may have to be served from these facilities as growth occurs on the system. There is no direct relationship between the number of line transformers and the number of customers. Many transformers serve more than one customer and there is not even a unique requirement to install a transformer for a given number of customers on many systems. In Cause No. 43111, the Company responded to OUCC Data Request No. 1-22 that, "Secondary transformers can serve as few as one customer and as many as twenty or more customers, depending upon the transformer size and proximity of customers." Line transformers are required to meet customer load requirements at all times. The peak demands on each transformer are caused by the coincidence of customer demands, or the lack of diversity of demands, not by the number of customers. Since there is no unique relationship between the number of customers and the number of line transformers, and since customer coincident demands are what drive the need to install more line transformers, it is incorrect to classify any portion of this plant as customer related. All line transformer plant should be classified as demand-related and allocated on class shares of the sum of individual customer maximum demands.

Q. What is your objection to the way Mr. Heid has implemented his classification of line transformers as partly customer-related?

A. While I believe the Commission should reject the classification of any part of line transformer plant as customer-related on a conceptual basis, the Commission should also reject Mr. Heid's implementation of the zero intercept method. The zero intercept method is based on developing a regression equation that relates the cost of transformers to the capacity of those transformers. It is the constant in this equation that forms the basis of the customer-related portion of each transformer. The worth of the customer-related estimate depends on the robustness of the statistical equation that Mr. Heid has estimated. My associate, Dr. Nicholson, has provided a detailed explanation of the shortcomings of Mr. Heid's statistical analysis and has demonstrated that Mr. Heid's estimate of the customer-related portion is unreliable, at best. Thus, even if the Commission were to accept the logic of classifying some significant portion of line transformers as customer-related, which I strongly believe it should not do, it must still reject Mr. Heid's estimate of that component because of the inadequate statistical analysis.

V. Uncollectible Accounts

Q. How has the Company allocated uncollectible accounts?

A. Mr. Heid has allocated these uncollectible costs among the classes in proportion to the class origin of these uncollectibles. Essentially, it amounts to a direct assignment. The bad debt that can be traced to the Residential class, for example, is assigned to the Residential class. Since most (83 percent) of the uncollectibles originate in the Residential class, this means that those residential customers that have paid their bills in a timely manner are required to carry the burden of all the residential customers that failed to pay their bills. This strikes me as patently unfair to the residential customers who have paid in a timely fashion.

Q. Why is it unfair to allocate to each class the uncollectibles it is responsible for?

A. Bad debts are essentially a general cost of doing business. It is no different than general administrative costs. The primary rule of cost allocation in an embedded class cost of service study is that costs should be allocated in the way those costs have been caused. Mr. Smith, a residential customer, is no more the <u>cause</u> of the bad debt of Mr. Jones (another residential customer) than is the XYZ Smelting Company, which might be served under Rate LP. Nor is the XYZ Smelting Company any more the <u>cause</u> of the bad debt associated with the failure of the ABC Cleaning Company (another LP customer) to pay its bills than is Mr. Smith. It is much more equitable, in my view, to recognize that bad debts are a general cost of doing business, and therefore to allocate these costs on a general allocator such as class revenue responsibility. This alternative is recognized in the 1992 NARUC Cost Allocation Manual (p. 103). In keeping with this more equitable logic, I have allocated these costs on the Company's Current Revenues, Input Allocator No. 6, Schedule 3, Exhibit KAH-S2.

VI. <u>Customer Service and Information Expenses</u>

Q. How has the Company allocated Customer Service and Information Expenses?

A. These expenses, booked in Accounts 907 through 910, amounting to $912,000, are allocated to customer classes on the basis of the number of customers.

Q. Do you agree with Mr. Heid's allocation of these costs?

A. No. There is no evidence that these costs are directly related to the number of customers. The general description of Account 908 (Customer Assistance Expenses), as provided in 18 CFR Ch. I (4-1-05 Edition) is: "This account shall include the costs of labor, materials used and expenses incurred in providing instructions or assistance to customers, *the object of which is to encourage safe, efficient and economical use of the utility's service* (emphasis added)." This theme extends to the description of

Accounts 906, 907, 909 and 910. The "utility service" in question is the delivery of electric energy, and so there is the presumption that the expenses booked in these accounts are more directly related to class energy use and not the number of customers. Moreover, a close inspection of the activities to be included in these accounts does not indicate any close and direct relationship between the number of customers and the total costs booked in these accounts. For example, in Account 908 are to be recorded the costs of the following:

1. Supervision;
2. Processing inquiries on proper use, replacement and information on electric equipment;
3. Advice on efficient and safe use of electric equipment;
4. Demonstrations, exhibits, lectures, etc. on safe, economical use or conservation;
5. Engineering and technical advice on safe, efficient and economical use;
6. Supplies pertaining to demonstrations or other programs;
7. Loss in value on equipment used for customer assistance programs; and
8. Incidental expenses.

None of these cost elements is in any clear way directly caused by the number of customers rather than the amount of service that is provided to the various classes, which is the general purpose of these expenses as stated in the FERC Uniform System of Accounts. Account 909 (informational and instructional advertising expenses) includes costs relating to preparing materials for newspapers, periodicals, etc., preparing informational booklets, preparing window and other displays, and the use of newspapers or other media for informational purposes. None of these activities bears any direct relationship to the number of customers. The same can be said of

Account 910, which is merely an account for recording expenses that do not neatly fit into Accounts 908 or 909. Moreover, the benefits of these expenditures to customers will depend on their size in terms of usage, and allocating on a simple customer count does not take into account the differing amount of usage among customers.

Q. How does the NARUC Cost Allocation Manual suggest these costs be classified?

A. The NARUC Manual states that, "…except for conservation and load management, these costs are classified as customer-related." However, this pronouncement seems to be in direct contradiction with how the Manual says Sales Expenses (Accounts 911 – 917) should be classified. In that case, the Manual states that, "These accounts include the costs of exhibitions, displays, and advertising *designed to promote the utility service* (emphasis added)." (p. 103) It goes on to say these costs could be classified as customer-related, but further states that "Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers," because they do not vary directly with the number of customers. Interestingly, that is what Mr. Heid does in his study. He allocates sales expenses on O&M costs without fuel, a much broader allocation factor than the number of customers. There is little difference in the types of costs that are incurred in these two groups of accounts. Whereas Sales Expenses are intended to "promote utility service," Customer Service and Informational Expenses are intended to "encourage safe, efficient, economical use of the utility's service." This is an instance where I believe the stated objective of the NARUC Cost Allocation Manual should be taken to heart. That is, that the Manual should be "non-judgmental" and not advocate any one particular method. (See Preface, p. ii.)

Q. How do you recommend these customer service and informational expenses be allocated among the customer classes?

A. I recommend that the sum of these costs be allocated among the various classes on the basis of their energy use at meter. That strikes me as being consistent with the purpose for which these expenses have been made -- the encouragement of safe, efficient and economical use of the utility's service.

VII. OUCC Cost of Service Studies

Q. Have you prepared a modified version of the Vectren South-Electric cost of service study that incorporates the changes you have discussed, including allocating generation and transmission plant investment on the peak and average allocator?

A. Yes. The Company provided Mr. Heid's May 17, 2010 revised cost of service model in Excel format with all formulas intact, which allowed us to rerun the model with the changes I believe are appropriate. Dr. Nicholson reviewed the structure of the model to ensure that she understands how it operates, and then reran the model with the changes that I have discussed in my testimony. Schedule DES-3 provides the summary pages for the OUCC Peak and Average study, and Schedule DES-4 provides the same summary for the alternative OUCC 12-CP study. In the first two pages of each Schedule, are provided the Statement of Operating Income at current revenues, first at actual rates and then at rates that would equalize rates of return for all classes. Page 3 provides the Statement of Operating Income at Company-proposed jurisdictional revenues and equalized class rates of return.

Q. Do class cost responsibilities change significantly when energy is properly recognized as being largely responsible for the amount of investment in generation and transmission plant, and when upstream distribution plant is properly classified as 100 percent demand-related?

A. Yes. This can be seen from a comparison of estimated class rates of return and class relative return indexes under the Company's 4-CP allocation and the class rates of return and "relative return indexes" that result from the OUCC Peak and Average Study, which allocates a significant portion of generation and transmission plant on energy use and classifies 100 percent of the cost of line transformers as demand-related. The "relative return index" is a class' rate of return expressed as a percentage of the jurisdictional average rate of return. This comparison between the two studies is provided in the first four columns of Schedule DES-5. The Residential rate of return rises from 4.78 percent under the Company's study to 6.34 percent under the OUCC P&A Cost Study. When proper account is taken of the energy responsibility for generation and transmission investments, and line transformers are properly classified as 100 percent demand-related, the Residential class is shown to be contributing a rate of return that is 115 percent of the system average rate of return, as compared to the Company's estimate of only 86 percent of the system average rate of return under the Company's 4-CP allocation method. Similarly, the relative return index for the Small General Service class rises from 56 percent under the Company's 4-CP study to 84 percent under the OUCC P&A study. The major classes whose relative return indexes fall significantly include Large Power Service, which falls from 147 percent to 64 percent; High Load Factor Service, which falls from 114 percent to 20 percent; and Street Lighting, which falls from 106 percent to 48 percent. This is a logical implication of the P&A method, since the first two of these classes are relatively high load factor classes, which means they will bear a larger responsibility for generation and transmission plant and related O&M costs when a significant portion of these costs are properly allocated on energy usage. The Street Lighting class return falls because it is no longer immune from being allocated production plant costs just because it misses the four highest monthly peaks.

Q. Please describe the second OUCC cost of service study that is summarized in Schedule DES-4.

A. If the Commission is unwilling to accept the results of the OUCC P&A study presented in Schedule DES-3, then I strongly believe the next best alternative is to adopt the 12-CP allocation of generation and transmission plant as opposed to the Company's proposed 4-CP methodology. The 12-CP results are provided in Schedule DES-4, and the rate of return comparisons for this study are provided in the 5th and 6th columns of Schedule DES-5.

Q. Why do you believe the 12-CP method is superior to the 4-CP method?

A. The 12-CP is a much broader reflection of usage than is the 4-CP, and I strongly believe that a broader allocator that recognizes year-round demands more accurately reflects the loads for which base load generation and transmission plant costs were incurred. Consider a class whose load is zero during each of the four critical summer peak hours, but has loads during the times of the other monthly peaks and during most of the other hours during the year. Under the relatively narrow 4-CP peak definition, that class would be allocated none of the costs of the generation plant that provides the customers in that class with energy and capacity during all the other times of the year. It is patently unfair for this class to be assigned none of the costs of the capacity that is used to meet its loads, while imposing all of those costs on those classes and customers who happened to be on the system during those four hours.

The 4-CP method is neither equitable nor an accurate reflection of the loads that caused the generation and transmission plant costs to be incurred in the first place.

Q. Does the P&A allocation method lead to symmetrical allocation of base load generation plant cost and the resulting savings?

A. Yes. Some critics of the P&A method have argued that it is somehow unfair to allocate additional production plant related costs to high load factor customers without providing those same customers with additional energy savings that result from those base load plants. These critics argue that the treatment of production plant costs and energy savings somehow lacks symmetry. What is meant by "additional production plant related costs," of course, is cost responsibility that is greater than would be allocated to them if production plant were classified as 100 percent peak demand related. This argument is entirely fallacious.

Q. How is this argument generally formulated?

A. It is usually demonstrated that, under a P&A method, the generation plant cost <u>per kW</u> is higher for high load factor classes than for low load factor classes. Then it is pointed out that total fuel cost is allocated on energy at source and so all classes pay the same fuel cost per kWh. Critics then conclude from this evidence that high load factor classes are treated unfairly and asymmetrically. That is, these classes are required to pay more per kW for generation plant but do not get the benefit of lower energy costs per kWh.

Q. What is wrong with this argument?

A. The problem with this comparison is that it <u>assumes</u> 100 percent of generation capital costs are demand related. That is the only basis for dividing total capital costs allocated to the various classes by their contributions to the appropriate measure of peak demand. If one accepts that some portion of generation capital costs are, in fact, energy related, then the comparison of unit capital costs needs to be separated into two portions – one on the basis of cost per kW, and the other on the basis of the cost per kWh. I have developed that very comparison in Schedule DES-6 for Vectren South-Electric.

Q. Please describe Schedule DES-6.

A. Schedule DES-6 shows the unit production plant cost and the unit fuel expense imposed on each class under the Company's 4-CP method (columns 3-6) and under the OUCC proposed Peak and Average allocation (columns 7-10). In the table I have unbundled the production plant cost into two components. The first is the demand related component, established as 45 percent based on the analysis in Schedule DES-2 and the Vectren South-Electric system load factor, which were used to separate these costs into the demand- and energy-related components. That portion is divided by each class' contribution to the 4-CP to determine the unit demand-related cost per kW. Note that, under the 4CP method, the amount is the same for all classes – $645.08 per kW. The second component is the energy-related portion, established as 55 percent, or 1.0 minus the peak demand component. That portion is divided by each class' energy at generator to determine the energy-related unit cost per kWh. Under the 4-CP method that results in widely varying units costs, with low load factor classes paying significantly more than high load factor classes. For example, the Residential class pays 22.61 cents per kWh, or 130 percent of the jurisdictional average cost of 17.43 cents per kWh. On the other hand, the higher load factor classes pay considerably less than the jurisdictional average. High Load Factor

Service pays only 9.15 cents, or about 52 percent of the average, and Large Power Service pays only 9.90 cents, or about 57 percent of the average. Outdoor Lighting and Street Lighting pay none of either the demand-related or energy-related generation capital costs.

Q. What are the results for the Peak and Average study that you propose?

A. The unit production demand-related costs are equal for all classes – the same $645.08 per kW. But, unlike the straight 4-CP method, the energy-related unit production costs are also equal – 17.43 cents per kWh. The last column shows that, for both methods, the unit fuel cost per kWh is equal for all classes -- 4.39 cents per kWh.

Q. What do you conclude from the analysis shown in Schedule DES-6?

A. Contrary to the argument raised by certain critics of the P&A method, if one accepts the reality that some portion of generation capital costs has been incurred to meet energy requirements, the Peak and Average allocation method provides perfect symmetry in the allocation of production capital costs and energy costs. All classes, regardless of their load factors, receive the same unit cost allocation of the demand-related component and the same unit cost allocation of the energy-related component. Then, all classes receive nearly identical allocations per kWh of fuel expense. The asymmetry actually exists in the 100 percent demand related 4-CP method because high load factor classes receive a lower cost per kWh of the energy related portion of production plant costs but receive the same unit fuel cost allocation as do low load factor classes. And this outcome is obvious if one thinks about it from a very practical perspective. Under the 100 percent demand related 4-CP method, when the Company decides to build a baseload unit with very high capital costs in order to generate fuel savings and lower energy costs, low load factor classes, like the

Residential class, are allocated a disproportionate share (47.9%) of those capital costs, but receive a much smaller share of the resulting energy savings (36.9%). High load factor classes, like the Large Power Service class, on the other hand, would be allocated a much smaller share of the capital costs (15.6%), but would receive a larger share of the resulting energy savings (27.4%).

If the Commission agrees that some portion of generation capital costs have been incurred to meet energy requirements, which I believe cannot be disputed, then the Commission cannot reject the P&A method on the grounds that it treats capital and energy cost allocations asymmetrically. The fundamental question that the Commission must answer is whether it agrees that some portion of generation capital costs have been incurred to meet energy requirements. If the Commission agrees with this proposition, then some method that recognizes energy in the classification of production capital costs, like my proposed P&A study, should be used to allocate these costs among the customer classes.

Q. Are fuel costs allocated among the classes to properly reflect differential losses in the Company's and your cost-of-service studies?

A. Yes. As the Company noted in response to OUCC 19-1, Proforma A (current revenues) fuel costs were allocated on sales volumes (energy use at meter), but Proforma B (proposed revenues) fuel costs were allocated on a line loss-adjusted basis (energy at generator). I have followed this procedure in both the OUCC P&A study and the OUCC 12-CP study.

Q. The Commission has never accepted an electric cost of service study that classifies a portion of generation and transmission costs as energy related. Should that prevent the Commission from doing so in this case?

A. No. While the Commission should surely consider the precedents it set in its earlier orders, it certainly is not restricted by its previous opinions if there is clear and convincing evidence that previously adopted methods should be changed. That is evidenced by its recent October 16, 2006 Order in Citizens Gas & Coke Utility (Cause No. 42767). There the Commission adopted the OUCC's proposed cost of service study that allocated distribution main costs on a combination of peak day consumption (20 percent) and annual volumes (80 percent). In that Order, the Commission stated:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding. (p. 74)

The method used by the OUCC in that case is directly comparable to allocating some significant portion of electric generation capital costs on annual energy use as I propose to do in this proceeding. I urge the Commission to evaluate the worth of the OUCC's P&A method in this case on "whether it is most reflective of cost causation."

VIII. <u>The Treatment of Special Contract Customers</u>

Q. How has the Company handled special contract customers in its cost of service study?

A. The Company has treated the sales to these customers outside of the cost of service study. It allocates the total costs of service, including the costs incurred to serve the special contract customers, to all those classes of customers that are explicitly recognized in the cost study. Then, it allocates the revenues received from sales to the special contract customers as credits to all the specifically identified classes. In short, it treats its special contract customers just like off-system, opportunity sales.

Q. Are there concerns in treating special contract customers in this manner?

A. Yes. Treating special contract customers outside of the cost of service study prevents a determination of what costs are actually being incurred to serve these customers. Consequently, there is no way of determining the amount of subsidy or discount that the special customers are receiving relative to the total embedded cost of providing them with service. This is especially important for Vectren South – Electric, because special contracts for the Company's two largest special contract customers account for approximately 13 percent of the total revenues at current rates.

Q. Could these customers be included in the cost of service study?

A. Yes, this can be done and I recommend that the Commission order the Company to do so in its next filed rate case.

Q. How do you recommend special contract customers be included in the Company's class cost of service study?

A. I recommend that the Company establish a customer class made up only of special contract customers. The Company would then determine the total embedded costs of serving the customers in that class. This total cost could then be compared to the revenues that the Company will actually receive from these customers based on the special contract terms, thereby enabling the Company, the Commission and all other interested parties, in determining the magnitude of the subsidy or discount that is being offered to this group of customers.

Q. Could the special contract customers simply be included in the rate class in which they would ordinarily be included if they did not have special contracts?

A. No. If that were done, then the amount of the subsidy these special contract customers are receiving would be combined with the subsidies being received or paid by the other customers in that class. Moreover, any move toward equalizing rates of return among classes based on the results of such a cost study would have the effect of imposing most or all of the burden of the subsidy to special contract customers on the remaining customers in that class. It is my view that providing subsidies to any particular customers or group of customers for economic/social reasons should be viewed as a system-wide benefit decision, and thus the costs of that subsidy should be borne by all customers on the system, not just other customers in that rate class.

IX. Class Step 1 Revenue Responsibilities

Q. Please describe Vectren South – Electric's proposed spread of its requested step 1 total jurisdictional revenue increase among the customer classes.

A. The Company proposes that the Company's requested step 1 jurisdictional revenue increase be spread among the classes so as to reduce the magnitude of the cross-subsidies at present rates that exist among the various customer classes. The Company's basis for the determination of the subsidy that each class is receiving or paying is the 4-CP class cost of service study that Mr. Heid has performed. The existing subsidies at current rates, based on the 4-CP study, and the amounts of the proposed subsidy reductions are presented in Petitioner's Exhibit KAH-S5. Mr. Ulrey explains that, in Cause No. 37803, the Commission directed that, in future cases, the magnitude of class subsidies should be reduced by at least 25 percent. However, Mr. Ulrey testifies that, in this case, the Company has proposed to spread the requested total jurisdictional increase so as to reduce existing subsidies by

12.5 percent for those classes providing a subsidy, and 13.96 percent for those classes receiving a subsidy. The exception is the Street Lighting Services class, which Mr. Ulrey proposes to limit to one-half the jurisdictional percentage increase. The resulting revenue spread leads to percentage step 1 revenue increases for the various customer classes that range from a low of 3.08 percent for the High Load Factor Service class to a high of 13.96 percent for the Small General Service class. The Residential class would receive an increase of 11.83 percent, or approximately 122 percent of the jurisdictional percentage increase of 9.69 percent, exclusive of Miscellaneous Revenues and Credits.

Q. Why has the Company proposed a class revenue spread that results in current subsidy reductions that are so much lower than the 25 percent reduction guideline provided by the Commission in Cause 37803?

A. The reasons provided by Mr. Ulrey are very illuminating. He first notes that the Commission in its Order in Cause No. 37803 tempered its guidance by noting that "any subsidy 'reduction should be prudent, consistent and whenever possible should avoid rate shock to any particular customer class'." (Exhibit JLU 1, p. 5.) Then, he goes on to explain that the peculiar circumstances of this case warrant smaller reductions in the existing subsidies. In particular, the subsidies in this case are much higher than in the previous case. This is due, as Mr. Ulrey explains, because there has been a large shift in the Production and Transmission Allocators from classes of larger customers to classes of smaller customers. This results because the "allocators in this case are based on usages during a time of reduced industrial production in relation to non-industrial load." (Id.)

Q. What is the implication of Mr. Ulrey's revelation that costs have been shifted from large, high load-factor customers to small, low load-factor customers?

A. It brings into question whether spreading the allowed increase in total jurisdictional revenues among the classes so as to move toward equal rates of return is fully appropriate in this case.

Q. Please explain.

A. It has largely been accepted as axiomatic that moving classes toward equal rates of return is an appropriate and fair objective in designing utility rates. The notion is that fair rates, other things constant, are rates that result in each class contributing revenues equal to the costs of serving the customers in that class. I, myself, have proposed that a reasonable objective would be, other things constant, to have classes contributing revenues that fall between 95 and 105 percent of the costs that are appropriately allocated to them, recognizing that cost of service studies produce what should be referred to as estimates of cost responsibilities and are not accurate enough to warrant the insistence on 100 percent equalization. However, the circumstances in this proceeding suggest that equalization of rates of return may not be a fully appropriate objective in guiding the spread of allowed revenue increases, because relative class cost responsibilities may vary widely over the business cycle.

Q. Why is that variation over the business cycle of importance as far as using cost of service as a guide to determining class revenue responsibilities?

A. That variation raises two concerns about fairness. First, shares of major allocators should be fairly stable over time. Otherwise the allocators will result in major swings in cost responsibilities and can lead to unfair allocation results. Consider, for example, that the Company has invested in significant baseload generation capacity to meet the energy requirements of all of its customers, but its large, high load-factor customers, in particular. Mr. Thomas Bailey has described in detail in his direct testimony the critical nature of industrial loads for Vectren South – Electric and what happens when these large industrial firms fall on hard times. Mr. Bailey explains that the Company's industrial rate class is comprised of 101 firms that account for 44 percent of the total energy usage. Indeed, Mr. Bailey explains that the Company's 15 largest industrial customers account for 75 percent of the Company's industrial margin. In response to OUCC data request 7-1, the Company stated that the "top five (5) industrial customers represent approximately 25% of the total energy usage on Vectren South's electric system." When these firms cut back on their usage, as Mr. Bailey testified has occurred over the last few years, the result is a significant amount of excess generation capacity. In response to OUCC data request 2-57, the Company stated that it would have an "estimated peak reserve of approximately 30%," when its planning reserve margin is only 15 percent. The cost of carrying this excess generation is disproportionately imposed on those low load factor classes made up of smaller customers whose loads have not fallen to the extent of loads in the industrial sector. Thus, whereas the amount of expensive baseload generation capacity has been determined in large part to meet the industrial need for less expensive energy, it is the Residential and Small General Service classes that are being required to pay for a disproportionate share of the excess generation capacity.

Q. What is the other concern?

A. Setting equal class rates of return as an objective of rate design is based on the notion that equalizing rates of return causes each class to pay the full cost of serving it. This is considered an important aspect of equity. However, the full cost of serving the various classes should also take into account the differential risk associated with serving the various classes. The volatility of industrial loads makes these loads much riskier to serve. The reduction in Vectren South -- Electric's industrial loads due to difficult economic times is what has led to the significant amount of excess generation capacity that the Company has to carry. In a competitive economy, the Company would probably have to bear most of those costs, but in the world of cost of service regulation those costs are being shifted on to other customers whose loads have not diminished by the same proportion. Given the differences in the risks associated with serving the various classes of customers, it makes sense to temper the equalized rates of return objective when spreading the allowed jurisdictional revenue increase among the customer classes.

Q. Have you developed a proposed spread of the Company-proposed step 1 revenue increase based on your Peak and Average cost of service study?

A. Yes. In Schedule DES-7, I develop one version of a spread of the Company's proposed step 1 revenue increase based on the class cost responsibilities that are provided in Schedule DES-3 – the OUCC Peak and Average study. I should note that I provide a spread of the Company's requested revenue increase only to facilitate comparison with the Company's proposed revenue spread, and this should not be taken as an endorsement of the Company's proposed revenue increase. The reasonableness of the Company's proposed increase in total revenues is addressed by other OUCC witnesses. In Schedule DES-8, I develop a similar class revenue spread based on the OUCC 12-CP cost study, the results of which are presented in Schedule DES-4.

Q. Please describe Schedule DES-7.

A. I began my development of a reasonable revenue increase spread by initially employing the Commission's directive in Cause 37803 that existing subsidies should be reduced by at least 25 percent, as long as the reductions are "prudent, consistent and wherever possible should avoid rate shock to any particular customer class." (Commission Order, Cause 37803, p. 11.) In the first page of Schedule DES-7, I show what the total revenue (rate revenue plus miscellaneous revenue) increases would be by mechanically applying the 25 percent subsidy reduction formula. The resulting percentage increases are presented in column 8. It should be noted that most of the increases are fairly similar, with the exceptions of Water Heating and Street Lighting, the increases for which are well in excess of the system average percentage increase. To ensure that the increases are prudent, consistent and do not result in rate shock for any of the classes, I decided to cap the increases for Water Heating and Street Lighting at 150 percent of the jurisdictional average percentage increase, or 11.35 percent. On page 2 of Schedule DES-7, I develop what I refer to as the Proposed Capped Revenues, which are shown in column 4. The shortfall from capping the Water Heating and Street Lighting classes are allocated among the other classes based on their shares of the uncapped revenue distribution, which shares are shown in column 2. The resulting percentage increases in total revenues are shown in column 5. In column 6 I deduct the Miscellaneous Revenue[16] for each class to arrive at the Proposed Capped step 1 Rate Revenues for each class in column 7. Column 8

[16] I have deducted Pro Forma B Equalized Miscellaneous Revenues to determine the rate revenues for each class in column 7. Since Miscellaneous Revenues are allocated, in part, on rate revenue less fuel costs, the rate revenues in column 7 provide a close approximation of the revenues that would result if Miscellaneous Revenues were reallocated to recognize the changes in class rate revenues as compared to equalized Miscellaneous Revenues.

presents the current rate revenue, and the percentage increases in step 1 class rate revenues are shown in column 9.

Q. Do you recommend that the total revenue increases and the rate revenue increases shown in columns 5 and 9 on page 2 of Schedule DES-7 be implemented if the Commission were to allow the Company its total requested jurisdictional increase?

A. While I believe this revenue spread meets the criteria established by the Commission in its Order in Cause 37803 and could reasonably be ordered by the Commission, I do not recommend that this revenue spread be adopted. An examination of the total revenue increases in column 5 shows that the capped increases do not vary a great deal among the classes. In addition, I believe the circumstances surrounding this case are such that it is not appropriate at this time to try and eliminate any existing cross-subsidies. A predominant aspect of this case is the huge reduction in industrial load, which has the effect of shifting cost responsibility to other classes of small, low load-factor customers. Given these circumstances, plus the fact that there are not large differences in required percentage increases among the classes, I strongly recommend that the Commission order that the allowed increase in this proceeding be spread among the classes on the basis of an equal percentage, across-the-board increase. Columns (2) and (3) of Schedule DES-9 present the OUCC-proposed class spread of total revenues and rate revenues based on the Company's requested step 1 increase.

Q. Does your evaluation of the appropriate class spread of the Company's proposed jurisdictional increase based on the OUCC 12-CP study in Schedule DES-8 modify your recommendation of an equal percentage, across-the-board increase?

A. No. While the differences among the required class increases to realize a 25 percent subsidy reduction are greater based on the results of the 12-CP study, I do not believe they are so great as to change my recommendation, especially when one takes into account the cost shifting that has occurred in this case because of the huge reduction in industrial loads.

X. The Spread of Any Step 2 Allowed Increase

Q. What is the OUCC's position regarding the appropriateness of the Company's requested Step 2 increase?

A. The OUCC opposes the Company's step 2 revenue increase in its entirety. This issue is addressed by OUCC witness, Tyler Bolinger

Q. Have you considered how any step 2 increase should be spread among the classes if the Commission were to adopt some portion of the Company's step 2 request?

A. Yes.

Q. What costs is the proposed step 2 revenue increase intended to recover?

A. The Company is requesting an additional $4.4 million in jurisdictional revenues to recover the costs associated with the "dense pack" installations at the Brown 1 and Brown 2 generating units.

Q. How has the Company proposed to spread this $4.4 million among the several customer classes?

A. Mr. Ulrey has proposed that these additional revenues be spread among the non-lighting classes based on the same percentage of the step 1 increase that was received by each class. Thus, the Residential class would receive 53.1845 percent of the non-lighting step 1 revenue increase under his proposal, and so the Residential class would receive 53.1845 percent of the step 2 increase. (See JLU-S5, Schedule 2.)

Q. Do you believe this is a reasonable way to spread the step 2 increase among the various customer classes?

A. No. First of all, there is no basis to excuse the lighting classes from bearing their appropriate share of these costs. Mr. Ulrey argues that, since these costs would be allocated with a 4-CP allocator if included in a cost of service study, and since the lighting classes do not contribute to the 4-CP allocator, they would not be allocated any of these costs in the context of a cost of service study. As I have argued above, all generation costs should be partially allocated on energy use or average demand. Otherwise classes like the lighting classes whose requirements are met by the Company's generation units would be improperly excused from paying for any portion of the capital costs that permit the production of the energy that these customers use. But to excuse these classes from paying for any part of the dense pack investment is particularly objectionable because this investment is clearly energy related.

Q. Please explain why the dense pack investment is clearly energy related.

A. The Company's own witness, Mr. Ronald Jochum, provides the explanation in his direct testimony. Mr. Jochum explains that the result of the dense pack installation "is improved steam path efficiency." He goes on to say that, "…the scheduled dense packs at Brown Units 1 and 2 will provide significant reductions in emissions of all pollutants, reduce the volume of ash produced at the units, and result in lower fuel costs." (Exhibit RGJ-1, p. 25.) Emissions, ash and fuel costs are each directly related to the amount of energy produced by these generating units. They are not related to the capacity of the units. Mr. Jochum responds to the question whether customers will receive immediate benefits when the dense packs are installed by stating that, "Fuel costs will be reduced and fewer allowances will be required to offset various types of regulated emissions." (Exhibit RGJ-1, p. 26.) In short, Mr. Jochum demonstrates clearly that the dense pack investment is being made to reduce fuel costs and to reduce the cost of emissions, both directly related to the production of energy.

Q. If these generation investment costs would have been allocated on the 4-CP in the Company's cost of service study, then what is wrong with distributing the step 2 revenue requirement in the same way?

A. The Company has made that argument. For example, that is the explanation of why the lighting classes are excused from any of the step 2 increase. It is also the explanation offered for allocating Environmental Emission Allowances (EEAs) on the 4-CP in the Reliability Cost and Revenue Adjustment (RCRA). In response to OUCC Data Request 1-13, Mr. Albertson states that "EEAs are in lieu of environmental capital investment at its generating plants that would render the EEAs unnecessary. It follows, then, that those costs should be allocated in the same manner as such capital investment would be allocated." There is some logic in Mr. Albertson's explanation, but the problem is that environmental capital investments should not be allocated on peak demand in the first place. It simply goes to show how inappropriate it is to allocate 100 percent of generation capital costs on peak demand. Investment in environmental control equipment has nothing to do with meeting capacity requirements or meeting reliability needs. The investments are made to reduce the amount of emissions that result from producing energy around the clock. Similarly, the dense pack investments are clearly being made to reduce fuel costs, ash by-product and emissions, all of which are related to the production of energy.

Q. How do you recommend that the proposed step 2 revenue increase be distributed among the customer classes?

A. I recommend that these costs be allocated among all the classes based on their energy use at generator. This step 2 revenue spread is provided in Schedule DES-9.

XI. Rate Design Issues

Q. Do you have any general comment on the overall changes that are being proposed by the Company in the design of its rates?

A. Yes. As a general proposition, the Company's proposed changes in its rate structure will shift revenue recovery from variable components of its rates to its fixed charges or to components of its rates that are less variable. Specifically, the Company's rate design proposals are designed to shift revenue recovery from energy charges to customer or facilities charges and to demand charges. This general redesign of its rates, along with the many cost tracker mechanisms that it is proposing, essentially has the effect of shifting risks from Vectren South – Electric to its customers.

Q. Do you have concerns with the implications of some of these proposed rate design changes?

A. Yes. I shall discuss below my concerns with the Company's proposed specific rate design changes for several of its current rate schedules.

Residential Rates

Q. Please describe the changes proposed by the Company for Residential Rate A and Residential Rate EH.

A. The Company has proposed to place Rate A customers and Rate EH electric heating customers on one rate schedule. Rate A customers will be defined as "Standard" customers and Rate EH customers will be defined as "Transitional" customers. Both types of customers will face a common monthly Customer Facilities Charge of

$11.00. That amounts to an increase of 100 percent for Rate A customers and 71 percent for Rate EH customers. Rate A customers currently face a two block declining rate for the first 250 kWh and everything over 250 kWh. The Company proposes to eliminate that two block feature for its new "Standard" customers. It proposes to significantly flatten the declining block feature for "transitional" customers, and to close this rate to new customers. Mr. Ulrey testifies that the Company's objective is to eliminate these declining blocks over time, which were originally introduced to encourage customers to install electric space heating. Let me first address the Company's proposed increases in the customer charges and then I will focus on the Company's proposal to flatten the rate schedule for electric space heating customers.

Q. Do you believe the Company's proposed increases in the Residential facilities charges are reasonable?

A. No. The Company's proposed increases in the Residential facilities charges violate the time-honored rate design criterion of gradualism or rate continuity. This proposal has the effect of imposing the largest percentage increases on the smallest customers taking service under these rate schedules, which is often related to the ability to pay. Further, I believe the Company's proposal unreasonably skews the breakdown of revenue recovery towards fixed charges. Mr. Ulrey's Exhibit JLU-S6 shows that, under the Company's proposal, 36 percent of revenues from RS-Standard customers, and 26 percent of revenues from RS-Transitional customers would be recovered through these increased facilities charges.

Q. How does the Vectren-South Electric proposed residential facilities charge compare with the fixed customer, service or facilities charges of other electric utilities in Indiana?

A. We conducted a survey of the Investor Owned Utilities (IOUs) and municipal utilities in Indiana to get a sense of where the Company's proposed residential facilities charge would fall in the distribution of these charges for other electric utilities in Indiana. The results of this survey are summarized in Schedule DES-10. These up-front charges for other IOUs range from $5.95 to $11.00, with an average of $7.97. I should note that the $11.00 charge is for Indianapolis Power and Light's larger residential customers with monthly usage exceeding 325 kWh per month. Below this level, the monthly charge is $6.70 per month. Customer charges for the municipal systems range from $3.47 to $10.00, with an average charge of $5.77 per month.

Q. In view of this evidence, what do you recommend regarding the appropriate increase in residential customer charges?

A. Given the very difficult current economic conditions that many residential customers find themselves in, and given that these difficult conditions are probably most severe for the smallest residential customers, I recommend that the Commission order the Company to retain the current facilities charges. At the very most, the Commission should limit the increase to approximately the overall jurisdictional percentage increase that it allows at the close of this case. Based on the Company's proposed 9.69 percent increase in jurisdictional rate revenues, that would amount to an increase to approximately $6.00 for RS-Standard customers and to approximately $7.00 for RS-Transitional customers.

Q. Do you have any concerns regarding the Company's proposal to close Rate EH (renamed RS-Transitional) to new customers and to begin to flatten that rate?

A. Yes. As Mr. Ulrey has testified, that rate was originally implemented to promote the use of electric space heating. Those customers that made investments in electric space heating systems did so with the reasonable expectation that lower tail block rates in Rate EH would continue to be available, at least for the life of their investments. That includes people who bought homes that had existing electric space heating systems already installed. I understand the Company's interest in phasing out the lower priced tail blocks in order to no longer promote the use of electric space heating. Presumably, the Company believes that future decisions about which heating systems to invest in should be based on the actual cost of operating electric heating systems. Thus, the Company appears to be interested in providing more accurate price signals upon which to base those future decisions. At the same time, consideration must be given to the equity of making changes that will have adverse effects on those customers who are locked into existing space heating systems.

Q. Please describe in detail the redesign of the rate blocks proposed by the Company, and the effects of these changes on "locked-in" customers.

A. The Company proposes to close the rate to new customers. It also proposes to begin to flatten the rate for RS Transitional customers. Specifically, it proposes to increase the "all-in" tail block rate for usage over 1,000 kWh in the winter from 7.526 cents/kWh to 8.697 cents/kWh, an increase of approximately 16 percent. This is offset to some extent by the reduction in the all-in rate for the first 250 kWh by 11 percent. The summer tail block all-in rate is increased by approximately 34 percent, or 2.55 cents/kWh. The effect of these changes is shown in the Company's bill comparisons, which are presented in Exhibit No. JLU-S7, on pages 2 and 3. The increase for a customer taking 2,000 kWh per month in the winter would be 11.56 percent, which is somewhat lower than the increase that is proposed by the Company for the Residential class as a whole -- 11.83 percent. The summer rate increase will be significantly higher. An RS-Transitional customer using 2,000 kWh in the summer will see an increase of 18.44 percent, based on the Company's bill comparisons. However, that monthly summer bill of $238.23 will still be about $69 less than the bill of a comparable 2,000 kWh customer taking service under RS-Standard.

Q. Do you find the redesign of Rate EH to be reasonable?

A. I believe the flattening of the rate that is included in the Company's redesign is a reasonable first step toward moving the rate serving electric space heating customers to the standard residential rate. However, I have serious misgivings regarding the equity of closing the rate to all new customers as the Company has proposed to do.

Q. Please explain your concern.

A. Customers who are locked into existing electric heating systems, the investment in which was based on the promotional rates that the Company offered, should be protected from the rate shock that would be associated with being forced to move onto Schedule RS – Standard. The Company has done this for existing Rate EH customers by grandfathering their right to remain on Rate RS – Transitional and by moderating the extent to which it has moved that rate toward the Rate RS – Standard. The problem is that the grandfathering is tied to the customer and not to the premises. That means when a customer buys an existing home with an electric heating system, he would be forced to pay for space heating at the rates embodied in RS – Standard. This customer is locked into the electric space heating system in the same way that the previous owner was. It is unreasonable to expect that new owner to invest in a new heating system after he buys the house and then learns that he will have significantly higher heating bills than did the seller. This situation can be easily avoided by tying the grandfathering provision to the premises rather than to the customer.

Q. Do you believe that the lower tail block rates should eventually be eliminated?

A. Yes. I believe that it would be reasonable to phase in the elimination of the lower tail block rates so as to merge this rate with Rate RS – Standard over something like a 10-year period, as long as existing RS – Transitional customers are made aware that their lower tail block rates will eventually be eliminated over this time period. That should provide ample time for customers to make rational decisions about which alternative heating system to install to replace the electric systems as they wear out. The combination of tying the grandfathering provision to the premises and the well-publicized gradual elimination of the lower tail block rates over a ten-year period would provide equitable treatment of those customers who are locked into electric space heating systems.

Small General Service Rate (SGS)

Q. Do you have any differences with the Company's proposed design of Rate SGS?

A. The Company has proposed to increase the customer facilities charge from \$7.50/month to \$11.00/month, an increase of 47 percent. As in the case of the Residential rate, I would urge the Commission to order the Company to retain the current customer facilities charge of \$7.50/month, or at least to limit the increase to the average jurisdictional percentage increase which, at the Company's proposed increase of 9.69 percent, would lead to a customer facilities charge of approximately \$8.50/month. Mr. Ulrey testifies that Rate SGS continues in its present form. However, the Company's proposal would increase the rate for usage over 2,000 kWh/month by nearly 22 percent, which is much higher than the increase in the other rate components, with no explanation of why it has proposed this restructuring. I recommend that the Commission order the Company to moderate the amount of the increase in this last block.

<u>Demand General Service (DGS)</u>

Q. Please summarize your understanding of the Company's proposed changes to Rate Schedule DGS.

A. The Company has proposed to separate customers in this class into three different size categories -- 10 kW to 70kW; 71 kW to 300 kW; and over 300 kW. Each of these three groups would have a different customer charge, but all other charges would remain the same for all three groups. I understand that the Company's purpose in introducing these three different size categories is that, "This sub-division allows for the eventual differentiation of Rates and Charges for these customers, based on size and cost differences, over time." (Ulrey Direct Testimony, Exhibit. JLU-1, page 10.) In short, it would seem that this size division merely sets the stage for potential further rate differentiation in the future.

Q. Does it make sense to differentiate these customers according to size?

A. There are likely to be some cost differences that are related to size that could be captured in different rates. However, the Company has provided no evidence of such cost differences. Indeed, I am aware of no evidence that the Company has provided to support the differences in the three different customer facilities charges. A much more likely factor causing differences in costs is voltage delivery level, which may or may not be associated with customer size.

Q. Are you concerned with the large increases in the customer facilities charges?

A. They are very large percentage increases. However, these charges are likely to be a very small portion of the total bills of large commercial and industrial customers, so the magnitude of these increases does not cause me as much concern as do the proposed increases for residential and small general service customers. Of somewhat greater concern is the shift in revenue responsibility toward customer and demand charges. The demand charge is proposed to be increased by 28 percent, while the energy charges in the last two blocks are proposed to increase by only 7.8 percent and 6.0 percent, and the first block energy charge would be reduced by about 2 percent. Again, I think this is representative of the entire thrust of the Company's restructuring of its rates and the Commission may wish to require the Company to moderate the extent to which it shifts revenue recovery from energy to demand and customer facilities charges.

Rate OSS – Off Season Service

Q. Who is this rate intended to serve?

A. This rate is available to any Non-Residential customer with a load in excess of 10 kW "who permanently and exclusively uses electric equipment for space heating." Thus, Rate OSS appears to provide the same reduced rate for larger Non-Residential space heating customers as Rate EH provides to Residential space heating customers.

Q. What changes does the Company propose to Rate OSS?

A. The Company proposes to increase the customer facilities charge by 43 percent, from $10.50 to $15.00 per month, and the demand charge is proposed to increase by 25 percent, from $4.00 to $5.00 per kW-month. The remainder of the required increase for this class comes from a nearly 8 percent increase in the flat energy charge.

Q. Does the Company propose to begin to eliminate the incentive space heating in this rate as it does for current Rate EH?

A. No. The structure of this rate relative to the standard service that such customers would take under Rate DGS remains largely unchanged. However, the incentives for space heating under this rate as compared to Rate DGS do not appear to be particularly large. The discount is fairly significant as compared to the first two blocks of Rate DGS. However, the all-in energy charge is actually higher by about 9 mills in Rate OSS as compared to the tail block rate in Rate DGS. The bill comparisons provided in Exhibit JLU-S7, page 6, show that smaller customers with usage under 15,000 kWh per month would continue to pay less than they would under Rate DGS, but larger customers with usage above 15,000 kWh would tend to pay more under Rate OSS.

Q. What do you conclude from your analysis of these two rates?

A. It is unclear to me what purpose Rate OSS fulfills or why it is proposed to continue for customers who "permanently" use electric equipment for space heating. It seems to me that the Company could close this rate to new customers, and begin to move the rate toward comparable DGS rates with the eye toward eliminating this rate within the next couple of rate cases.

<u>Rate LP - Large Power Service</u>

Q. Do you have any comments on the Company's proposed design of Rate LP – Large Power Service?

A. I would only observe that in the design of Rate LP, the Company continues with its effort to shift revenue recovery from energy charges to up-front facilities charges and to demand charges. It proposes to increase the monthly facilities charge by 25 percent, to increase the demand charge by 18 percent, and to increase the all-in energy charge by only 1.6 percent. The Commission may wish to temper somewhat this shift in revenue recovery to less elastic components of service, thereby tempering to some extent the shift of the risk of revenue recovery from the Company to its customers.

Q. Does this complete your direct testimony?

A. Yes.

VERIFICATION

STATE OF MARYLAND)
) ss:
COUNTY OF HOWARD)

The undersigned, Dale E. Swan, under penalties of perjury and being first duly sworn on his oath, says that he is a Vice President and Principal of Exeter Associates, Inc., a Consultant for the Indiana Office of Utility Consumer Counselor; and in the matter of Cause No. 43839 that he caused to be prepared and read the foregoing that the representations set forth therein are true and correct to the best of his knowledge, information and belief.

Dated: June 24, 2010

Dale E Swan
By:

Subscribed and sworn to before me, a Notary Public, this 24 day of June 2010.

Deborah M Adams
Signature

Deborah M Adams
Printed Name

My Commission Expires: 2/2011

My County of Residence: PG

RESUME

DR. DALE E. SWAN

DALE E. SWAN

Dr. Swan is a senior economist and principal at Exeter Associates, Inc. His areas of expertise include energy supply planning, electric industry restructuring, utility cost allocation and rate structure design, utility contract negotiation, antitrust policy, and public utility regulation.

Dr. Swan has presented expert testimony in utility rate cases before the Federal Energy Regulatory Commission and before numerous state regulatory commissions. He has testified on marginal and embedded costing, rate structure design, long-term demand forecasting, short-term sales forecasts, the treatment of off-system sales, electric industry restructuring, and antitrust considerations. He has directed major projects for the U.S. Department of Energy, the U.S. Air Force, and the Rhode Island Public Utilities Commission on such issues as alternative power supply options and innovative rate structure experiments and implementation, and he has prepared and presented seminars and workshops on such issues as marginal costing, rate design, and interruptible rates for, among others, the National Regulatory Research Institute, the U.S. Department of Energy, and for state commission staffs in Maryland, Minnesota, and New Hampshire.

Dr. Swan has assisted federal agencies in the negotiation of electric power supply contracts and in the financial and locational assessment of transmission and generation projects. He has also prepared reports to several federal and state agencies on costing methods, rate design, the demand for electric power, PURPA requirements, bulk power supply planning, stranded cost recovery, standby rates, value-of-service pricing, the use of special contracts, and other issues. He has also acted as an Advisor to the Maine Public Utilities Commission in the restructuring proceedings for the three investor-owned Maine electric companies.

Education:

B.S. (Business Administration) - Ithaca College, 1962.

M.A. Program in Economics - Tufts University, 1962-63.

Ph.D. (Economics) - University of North Carolina at Chapel Hill, 1972.

Previous Employment:

1976-1980	-	Senior Economist, J. W. Wilson & Associates, Inc.
1974-1976	-	Associate Professor of Economics, Jacksonville State University
1974	-	Economist, Office of Energy Systems, Federal Energy Administration
1973	-	Staff Economist, Economics Department, Arabian-American Oil Company

1968-1973	-	Assistant and Associate Professor of Economics, Hampden-Sydney College
1969-1973	-	Visiting Assistant Professor of Economics, Randolph-Macon Woman's College
1967-1968	-	Assistant Professor of Economics, Southern Methodist University
1966-1967	-	Visiting Assistant Professor of Economics, North Carolina Central University
1963-1964	-	Market Research Analyst, The Carter's Ink Company

Previous Professional Work:

At J.W. Wilson & Associates, Inc., Dr. Swan had primary responsibility for the development and direction of several of the firm's largest projects relating to the electric utility industry and costing and rate design issues in particular. Dr. Swan also had major responsibilities in the areas of cogeneration, antitrust, PURPA requirements, and technical assistance to state regulatory authorities under DOE grant programs.

At the Federal Energy Administration, Dr. Swan participated in the development of a National Energy Accounting System, similar to and compatible with the National Income and Product Accounts and the U.S. Input/Output Accounts. During his tenure at Jacksonville State University, Dr. Swan continued with this work as a consultant to the FEA.

While with ARAMCO, Dr. Swan prepared financial analyses of capital investment alternatives, developed cost trend estimates for price negotiations, and initiated the preparation of revised price trend factors to be used for budgeting purposes.

At Carter's Ink Company, Dr. Swan was responsible for conducting new product and new market research for the Director of Marketing, including consumer attitudinal studies on new product and packaging designs.

Dr. Swan has taught both graduate and undergraduate courses during his academic career. Among the courses he has taught are Microeconomic Theory, Industrial Organization, Economic History, International Trade, Economic Development, and Principles of Economics.

Selected Publications, Papers, and Reports:

"The Northern California DOE Laboratory Electric Power Purchasing Consortium: A History," (Exeter Associates, Inc.) for the U.S. Department of Energy, Federal Energy Management Program, September 2009.)

"Electric Power Options Study Follow-up Report for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2008.)

"Updated Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, April 2007.)

"Fermi National Accelerator Laboratory Phase 1 Electric Supply Options Study," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, December 2004.)

"Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2004).

"Phase 1 Electric Supply Options Study for Fermi National Accelerator Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, December 2004).

"Electric Power and Natural Gas Supply Options Study for the DOE Oak Ridge Reservation," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, March 2004).

"A Comparative Evaluation of Two Proposals to Meet the Long-Term Steam Requirements of the Savannah River Site." (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, November 2001.)

"Electric Power Supply Options to Meet the Cold Standby and Possible Restart Requirements of the Portsmouth Gaseous Diffusion Plant." (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, October 2001.)

"Strategic Options in Planning for the Long-Term Power Requirements of the DOE/OAK Laboratories." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, September 1998.)

“Utility Options Study: Rocky Flats Environmental Technology Site.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, March 1997.)

“Competitive Acquisition of Power by Federal Agencies: Current Possibilities and Future Prospects.” (Presented before the Competitive Power Congress, Philadelphia, Pennsylvania, July 21, 1995.)

“Standby Rate Rulemaking: A Discussion of Issues and Proposed Positions.” (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 10, 1995.)

“Stranded Cost Rulemaking: A Discussion of Issues and Proposed Positions.” (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 3, 1995.)

“Superconducting Super Collider Permanent Power Supply: A Preliminary Consideration of Supply Alternatives.” (Exeter Associates, Inc., revised draft report prepared for the U.S. Department of Energy, Office of Organization, Resources and Facilities Management, March 1992.)

"The Potential Savings Associated with Exporting EBR-II Energy from the Idaho National Engineering Laboratory to Another Federal Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, March 1991.)

"Planning and Preparing a Utilities Options Study," in <u>Utilities Planning and Management for Department of Energy Facilities</u>. (U.S. Department of Energy, February 1990.)

“An Evaluation of the Financial Benefits to the United States Government from Using $175 Million of the TRNLC Fund to Purchase Generating Capacity to Reduce Power Costs of the Superconducting Super Collider.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, January 1990.)

"Power Supply Arrangements at Brookhaven National Laboratory." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, October 1989.)

"Electric Power Supply Options for the Continuous Electron Beam Accelerator Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, July 1989.)

"The Potential Future Value of Byproduct Steam from a New Production Reactor Based on Four Alternative Technologies and Three Alternative Sites," with Steven Estomin and Richard Galligan. (Exeter Associates, Inc. for the U.S. Department of Energy, August 1988.)

"An Analysis of the Optimal Allocation of Available Western Area Power Administrative Preference Power Among Three Northern California Laboratories," with Charles E. Johnson. (Exeter Associates Inc. for DOE San Francisco Operations Office, March 1986.)

"Report on the Role of Special Contracts in Electric and Gas Utility Ratemaking." (Exeter Associates, Inc. for the U.S. Postal Service, February 1984.)

"The Electric Utility Industry," in Study of Pricing Precedents in the Public Utility Industry. (Exeter Associates, Inc., for the U.S. Postal Service, February 1984.)

"State Regulatory Attitudes Toward Fuel Expense Issues," with Matthew I. Kahal, Report to the Electric Power Research Institute, June 1983.

"A Summary and Analysis of Federal Legislation Affecting Electric and Gas Utility Diversification." (Exeter Associates, Inc. for Argonne National Laboratory, August 1981.)

"Average Embedded Cost Studies as the Basis for Rate Designs Consistent with the Goals of the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 6, 1981.

"Analysis of the Major Comments Made on the ERA Proposed Voluntary Guideline for the Cost-of-Service Standard Under the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 1981.

"The Rhode Island - DOE Electric Utilities Demonstration Project." Final Report - November 1980, and three Interim Reports in July 1978, November 1979, and July 1980. (J.W. Wilson & Associates, Inc. for the Rhode Island Division of Public Utilities and Carriers.)

"An Evaluation of Power Supply Planning by the Six Investor-Owned Electric Utilities in South Dakota," with Ralph E. Miller. (J.W. Wilson & Associates, Inc. for the South Dakota Public Utilities Commission, 1977.)

The Structure and Profitability of the Antebellum Rice Industry: 1859. (New York: Arno Press, 1975.)

"The Structure and Profitability of the Antebellum Rice Industry: 1859." Journal of Economic History, (December 1972.)

"The Productivity and Profitability of Antebellum Slave Labor: A Micro Approach," with James D. Foust. Agricultural History, (January 1970). Later published in William N. Parker (ed.), The Structure of the Cotton Economy of the Antebellum South. (New York: Agriculture History Society, 1970.)

Participation in Conferences, Seminars and Workshops:

Competitive Power Congress, 1995.

Department of Energy Utility Conferences, 1985, 1986, 1990, 1992, 1995, 1996, 1997.

DOD/DOE Combined Utility Planning Conference, March 1987.

American Historical Association Meetings, 1981.

National Regulatory Research Institute Workshop on Time-of-Use Rates, September 1979.

National Regulatory Research Institute State Needs Assessment Conference, August 1979.

Southern Economic Association Meetings, 1969, 1972, 1975.

Economic History Association Meetings, 1972.

Expert Testimony

Presented by Dale E. Swan

1. Before the Public Utilities Commission of the State of Ohio, Case No. 78-676-EL-AIR, on marginal costs and electric rate structure design.

2. Before the Public Utilities Commission of the State of South Dakota, Docket No. 3362, on marginal costs and electric rate structure design.

3. Before the Public Utilities Commission of the State of South Dakota, Docket Nos. F-3240 and F-3241, on electric rate structure design.

4. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1311, on the design of a proposed inverted rate structure experiment.

5. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1262, on the operation and the results of a time-of-day rate experiment.

6. Before the Public Utilities Commission of the State of South Dakota, Docket No. F-3116, on test year sales forecasts.

7. Before the Public Utilities Commission of the State of Montana, Docket No. 6441, on test year sales forecasts.

8. Before the Public Service Commission of the State of Maryland, Case No. 6807, on long-term demand forecasting methodology.

9. Before the Public Service Commission of the State of New York, Docket No. 27136, on test year sales forecasts and economic impact.

10. Before the Federal Energy Regulatory Commission, Docket No. ER77-530, on retail competition in the Ohio electric power market.

11. Before the Public Service Commission of the State of Maryland, Case No. 7441 (Phase III), on electric rate structure design and PURPA ratemaking standards.

12. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1591, on class revenue requirements and electric rate structure design.

13. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1606, on PURPA Section 111 standards, class cost-of-service, and rate structure design.

14. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1605, on class revenue requirements and electric rate structure design.

15. Before the Public Utilities Commission of the State of Idaho, Case No. U-1006-185, on class revenue requirements and rate design.

16. Before the Illinois Commerce Commission, Docket No. 82-0026, on marginal-cost-based class revenue responsibilities and rate design.

17. Before the Public Utilities Commission of the State of Idaho, Case No.. U-1009-120, on contractual arrangements, embedded-cost-based class revenue requirements, and rate design.

18. Before the Public Utilities Commission of the State of Maryland, Case No. 7695, on proper electric class cost-of-service methodologies.

19. Before the Public Service Commission of Nevada, Docket No. 83-707, on marginal-cost-based class revenue responsibilities and rate design.

20. Before the Illinois Commerce Commission, Docket No. 83-0537, on marginal-cost-based class revenue responsibilities, rate design, and rate schedule qualification standards.

21. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-137, on jurisdictional separations, embedded class cost-of-service studies, interruptible service credits, and class revenue requirements.

22. Before the South Carolina Public Service Commission, Docket No. 84-122-E, on embedded class cost-of-service methodologies, class revenue requirements, and rate design.

23. Before the Public Utilities Commission of the State of Idaho, Case No. U-1500-157 (May 1985), on the public interest aspects of declaring one utility as the sole supplier of the Idaho National Engineering Laboratory.

24. Before the Illinois Commerce Commission, Docket Nos. 83-0537 (Step 2) and 84-0555 (Consolidated), June 1985, on marginal-cost-based class revenue responsibilities and rate design.

25. Before the Public Utilities Commission of the State of Idaho. Case No. U-1006-265A (May 1987), on embedded class cost-of-service studies, class revenue requirements, and rate design.

26. Before the Public Utilities Commission of the State of Maine, Docket No. 86-242 (August 1987), on by-pass and incentive rate discounts for large industrial customers.

27. Before the Illinois Commerce Commission, Docket No. 87-0427, (February and April 1988), on marginal-cost-based class revenues, Ramsey pricing considerations, and industrial rate design.

28. Before the Illinois Commerce Commission, Docket No. 87-0695, (April 1988), on marginal-cost-based class revenues, Ramsey pricing issues, and industrial rate design.

29. Before the Indiana Utility Regulatory Commission, Cause No. 37414-S2 (October 1989), on ratemaking treatment of off-system sales, embedded cost-of-service study, and rate design.

30. Before the Public Utilities Commission of the State of Maine, Docket 89-68 (January 1990), on measurement and use of marginal costs for determining class revenues.

31. Before the Federal Energy Regulatory Commission, Docket No. EC90-10-000, et. al. (May 1990), with Matthew I. Kahal, on the potential effects of the Northeast Utilities acquisition of Public Service New Hampshire on market concentration and competition in the New England bulk power market.

32. Before the Illinois Commerce Commission, Docket No. 90-0169 (August and October 1990), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

33. Before the Public Service Commission of Nevada, Docket Nos. 91-5032 and 91-5055 (September 1991), on the estimation of marginal costs, class revenue responsibilities and rate design for large power users.

34. Before the Public Service Commission of Nevada, Docket No. 92-1067 (May 1992), on the estimation of marginal costs, the cost of providing interruptible power, class revenue responsibilities, and rate design for large power users.

35. Before the Public Utilities Commission of the State of Maine, Docket No. 92-095 (February 1993), Affidavit regarding the efficacy of rate discounts in attracting new business.

36. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (June 1993), on revamping of the rate structure to meet competition for sales.

37. Before the Public Utilities Commission of the State of Maine, Docket No. 92-345 (August 1993), with Marvin H. Kahn, on price cap mechanisms as an alternative form of regulation.

38. Before the Public Service Commission of Nevada, Docket No. 92-9055 (October 1993), on franchise rights to serve a large DOE customer.

39. Before the Illinois Commerce Commission, Docket No. 94-0065 (June 1994), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

40. Before the Public Service Commission of Nevada, Docket No. 93-11045 (June 1994) on the estimation of marginal costs, environmental externality adders, competition for loads, and class revenue responsibilities.

41. Before the Idaho Public Utilities Commission, Case No. IPC-E-94-5 (November 1994), on embedded class cost allocation and class revenue responsibilities.

42. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (II) (March 1995), on the estimation of marginal distribution demand and customer costs.

43. Before the Public Utilities Commission of the State of Maine, Docket No. 95-052 (RD) (October 1995 and January 1996), with Daphne Pscharopoulos, on the estimation of marginal costs as the basis for class revenues and rate design.

44. Before the Public Service Commission of Nevada, Docket No. 96-7020 (November 1996), on the estimation of marginal costs, class revenue responsibilities, and the reasonableness of fixed, up-front facilities charges.

45. Before the Public Service Commission of Montana, Docket No. 97.7.90 (November 1997 and March 1998), on aspects of Montana Power Company's proposed restructuring plan.

46. Before the Illinois Commerce Commission, Docket No. 99-0117 (April 1999), on the design of distribution delivery rates for Commonwealth Edison Company.

47. Before the Public Utilities Commission of Nevada, Docket Nos. 99-4005 and 99-4006, (November 1999), on the design of an electric distribution service tariff for Nevada Power Company.

48. Before the Public Utilities Commission of Nevada, Docket No. 99-7035 (January and February 2000), on Nevada Power proposed revision to its base rates and deferred energy adjustment rates, including the recovery and allocation of deferred capacity costs and the appropriate calculation of annualized fuel and purchased power costs.

49. Before the Illinois Commerce Commission, Docket No. 01-0423 (August, October 2001), on the proper design of distribution delivery rates for Commonwealth Edison Company.

50. Before the Public Utilities Commission of the State of Maine, Docket No. 2001-239 (November 2001), on appropriate procedures governing the provision of rate discounts to retain or attract customers.

51. Before the Public Utilities Commission of Nevada, Docket Nos. 01-10001, 01-10002 and 01-11029 (February 2002), on Nevada Power Company's proposed class cost allocations and revisions to its base rates.

52. Before the Illinois Commerce Commission, Docket No. 02-0479 (August 2002), on the appropriateness of the Company's petition to have bundled Rate 6L service to customers with loads of 3 MW or more declared a competitive service, thereby eliminating Rate 6L as a service of last resort for these customers.

53. Before the Illinois Commerce Commission, Docket Nos. 02-0656, 02-0671, and 02-0672 (CONS.) (December 2002), on proposed changes to Commonwealth Edison Company’s retail access options.

54. Before the Public Utilities Commission of Nevada, Docket Nos. 03-10001 and 03-10002 (January 2004), on Nevada Power Company’s proposed class revenue allocation and the imposition of new Customer Specific Facilities Charges on certain large customers.

55. Before the Illinois Commerce Commission, Docket No. 05-0159 (June 2005), on the need for Commonwealth Edison Company to offer a fixed-price POLR service to large customers.

56. Before the Illinois Commerce Commission, Docket No. 05-0597 (February 2006), on the allocation of costs and the design of rates for retail delivery service.

57. Before the Illinois Commerce Commission, Docket No. 07-0566 (February 2008), on embedded class cost of service and the design of rates for retail delivery service.

58. Before the Indiana Utility Regulatory Commission, Cause No. 43306 (September 2008), on embedded class cost of service and the design of rates for retail customers.

59. Before the Indiana Utility Regulatory Commission, Cause No. 43526 (May 2009), on embedded class cost of service, revenue spread and rate design.

60. Before the State of Rhode Island and Providence Plantations Public Utilities Commission, Docket No. 4065 (September 2009), on embedded class cost of service, revenue spread and rate design.

61. Before the Pennsylvania Public Utility Commission, Docket No. M-2009-2123944 (October 2009), on the proper allocation of the costs of Smart Meter Technology.

62. Before the Pennsylvania Public Utility Commission, Docket No. M-2009-2123948 (October 2009), on the proper allocation of the costs of Smart Meter Technology.

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND	)	
ELECTRIC COMPANY	)	
d/b/a VECTREN ENERGY	)	**CAUSE NO. 43839**
DELIVERY OF INDIANA, INC.	)	
(VECTREN SOUTH - ELECTRIC)	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

DR. DALE E. SWAN - PUBLIC'S EXHIBIT NO. 13

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JUNE 25, 2010

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

VECTREN SOUTH-ELECTRIC
Generating Plant Information
2007-2009

Unit	Net Capacity (MW)	Fuel Type	Plant Type	Average Generation (mWh)		Average Hours Connected To Load
Brown 1	245	Coal	Baseload	1,364,883		7,274
Brown 2	245	Coal	Baseload	1,533,438		8,035
Culley 2	90	Coal	Baseload	442,517		6,587
Culley 3	270	Coal	Baseload	1,765,026		8,010
Warrick 4	150	Coal	Baseload	907,016		7,550
Brown 3	80	Gas/Oil	Peaking	13,683		309
Brown 4	80	Gas	Peaking	14,558		241
Broadway 1	50	Gas	Peaking	2,105		74
Broadway 2	65	Gas/Oil	Peaking	16,200		379
Northeast 1	10	Gas	Peaking	38		4
Northeast 2	10	Gas	Peaking	41		4
Blackfoot	3	Landfill gas	Baseload	9,655[1]		NA
System Total	1,298			6,069,160		
Total Peaking	295	(22.7%)		46,625	(0.8%)	169
Total Baseload	1,003	(77.3%)		6,022,535	(99.2%)	7,491[2]

[1]The Blackfoot unit only operated in 2009.
[2]Excludes Blackfoot.

Source: Company's response to OUCC Request 2-5.

Vectren South-Electric
Analysis of Demand and Energy Responsibility
for Cost of Existing Generation Plant
(Based on Original Installed Cost of Plant)

	Year of installation[1]	Installed Capacity[2] (MW)	Original Installed Cost Nominal[2] ($/kW)	Original Installed Cost ($ 2009)[3] ($/kW)
Peaking Units				
Brown 3	1991	83.3	352.43	531.73
Brown 4	2002	84.4	378.83	511.63
Broadway 1	1971	51.8	212.16	995.08
Broadway 2	1981	74.4	144.50	252.95
Northeast 1	1963	10.5	156.22	875.44
Northeast 2	1964	10.5	156.22	875.44
Peaking Subtotal		314.9	274.22	559.62
Base Load				
Brown 1	1979	240.2	1,300.03	2,230.47
Brown 2	1986	240.2	1,300.03	2,230.47
Culley 2	1966	95.7	1,059.88	5,167.66
Culley 3	1973	287.2	1,059.88	5,167.66
Warrick 4	1970	150.0	423.15	2,063.16
Blackfoot	2009	3.2	3,612.19	3,612.19
Base load Subtotal		1,016.5	1,087.45	3,316.53
Total		1,331.4	895.11	2,664.47

	$1000s	Percent	Nominal Calculation	
Total Installed cost ($1,000s of 2009 dollars)	$3,547,477	100%	1,191,749	100%
Less Peaker Cost ($559.62/kW x 1,331.4 MW)	$745,078	21.0%	365,097	31%
Energy-related Cost	$2,802,399	79.0%	826,653	69%

\1: Source: Vectren South (Southern Indiana Gas and Electric Company) 2008 FERC Form 1, the Energy Information Administration's EIA 806 Database; press release (Blackfoot).

\2: Source: Vectren South-Electric's Response to OUCC DR1-Q5

\3: Nominal dollars were converted into 2009 dollars with the "Intermediate materials supplies and components" (Series Id: WPUSOP2000Producer Price Index), Bureau of Labor Statistics. A single total installed cost figure was provided for Brown units 1 and 2, which were built in 1979 and 1986 respectively. I assumed that the total installed cost was provided in 1983 dollars. Similarly, the Culley unit total cost figure was treated as if it were provided in 1970 dollars and the Northeast unit total cost figure was treated as if it were provided in 1964 dollars.

Vectren South-Electric
Analysis of Demand and Energy Responsibility
for Cost of Existing Generation Plant
(Based on Replacement Cost of Plant)

	Installed Capacity[1] (MW)	Replacement Cost per kW[2]	Total Replacement Cost	Cost if 100% Peaking Capacity
		($)	($1,000)	($1,000)
Peaking Units				
Brown 3	83.3			
Brown 4	84.4			
Broadway 1	51.8			
Broadway 2	74.4			
Northeast 1	10.5			
Northeast 2	10.5			
Peaking Subtotal	314.9	1,166	367,173	
Base Load				
Brown 1	240.2			
Brown 2	240.2			
Culley 2	95.7			
Culley 3	287.2			
Warrick 4	150.0			
Blackfoot	3.2			
Base load Subtotal	1,016.5	3,043	3,093,210	
Total - All Types	1,331.4		3,460,383	1,552,412

Demand-Related Share	(1,552,412 ÷ 3,460,383) x 100 = 44.9%
Energy-Related Share	100 - 44.9% = 55.1%

1/ Vectren South-Electric Response to OUCC DR1 Q-5

2/ Vectren 2009 Integrated Resource Plan, pages 76-77. The baseload replacement cost is based on a CFB coal plant and the peaking replacement cost is based on a Heavy Duty GE 7EA gas unit.

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC PEAK AND AVERAGE COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA A REVENUES AT PRESENT RATES OF RETURN

DATA: 12 MONTHS ENDED JUNE 30, 2009

Line No.	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Operating Revenues										
(1)	Revenues From Electric Sales	$450,757,539	$195,346,609	$1,332,230	$8,599,120	$130,516,100	$10,503,760	$94,886,129	$5,833,238	$1,136,718	$2,603,635
(2)	Miscellaneous Revenues	$102,901,084	$42,808,404	$349,895	$1,850,434	$29,620,554	$2,449,871	$23,620,442	$1,565,196	$203,163	$433,124
(3)	Total	$553,658,624	$238,155,013	$1,682,125	$10,449,554	$160,136,654	$12,953,631	$118,506,571	$7,398,435	$1,339,882	$3,036,759
	Operating Expenses										
(4)	Operation and Maintenance	$369,952,743	$147,354,395	$1,279,183	$7,025,065	$104,801,993	$8,970,303	$91,148,118	$6,340,861	$862,945	$2,169,879
(5)	Depreciation and Amortization	74,255,452	33,335,717	286,166	1,563,127	21,111,443	1,799,426	14,484,671	895,944	239,595	539,364
(6)	Federal Income Taxes	16,132,807	9,880,629	(35,125)	205,427	5,583,697	240,833	428,749	(171,995)	30,309	(29,717)
(7)	State Income Taxes	5,916,817	3,345,514	(3,565)	87,367	1,950,047	103,053	444,351	(25,269)	12,306	3,012
(8)	Taxes Other Than Income	15,795,139	6,985,530	56,222	321,180	4,514,391	376,558	3,189,174	197,001	41,307	113,775
(9)	Total	$482,052,957	$200,901,786	$1,582,881	$9,202,165	$137,961,571	$11,490,173	$109,695,063	$7,236,542	$1,186,463	$2,796,313
(10)	Net Operating Income	$71,605,667	$37,253,227	$99,244	$1,247,389	$22,175,083	$1,463,458	$8,811,508	$161,892	$153,419	$240,446
(11)	Original Cost Rate Base	$1,294,271,919	$587,664,254	$5,103,731	$26,836,270	$366,959,688	$31,604,796	$249,195,718	$14,936,195	$2,927,826	$9,043,444
(12)	Rate of Return on Rate Base	5.53%	6.34%	1.94%	4.65%	6.04%	4.63%	3.54%	1.08%	5.24%	2.66%
(13)	Earnings Index	100%	115%	35%	84%	109%	84%	64%	20%	95%	48%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC PEAK AND AVERAGE COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA A REVENUES AT EQUALIZED RATES OF RETURN

DATA: 12 MONTHS ENDED JUNE 30, 2009

Line No.	Description	Total (1)	Residential (RS) (2)	Water Heating (B) (3)	Small General Service (SGS) (4)	Demand General Service (DGS) (5)	Off-Season Service (OSS) (6)	Large Power Service (LP) (7)	High Load Factor Service (HLF) (8)	Outdoor Lighting (OL) (9)	Street Lighting (SL) (10)
	Operating Revenues										
(1)	Revenues From Electric Sales	$450,757,539	$188,101,015	$1,613,272	$8,977,324	$127,614,519	$10,943,462	$102,482,093	$6,849,407	$1,154,801	$3,021,647
(2)	Miscellaneous Revenues	$102,901,084	$41,959,285	$381,532	$1,877,471	$29,323,949	$2,496,942	$24,519,755	$1,683,585	$199,703	$458,863
(3)	Total	$553,658,624	$230,060,300	$1,994,804	$10,854,795	$156,938,468	$13,440,405	$127,001,848	$8,532,992	$1,354,503	$3,480,510
	Operating Expenses										
(4)	Operation and Maintenance	$369,952,743	$147,354,395	$1,279,183	$7,025,065	$104,801,993	$8,970,303	$91,148,118	$6,340,861	$862,945	$2,169,879
(5)	Depreciation and Amortization	74,255,452	33,335,717	286,166	1,563,127	21,111,443	1,799,426	14,484,671	895,944	239,595	539,364
(6)	Federal Income Taxes	16,132,807	7,327,961	63,478	333,220	4,575,149	394,338	3,107,734	185,788	34,920	110,220
(7)	State Income Taxes	5,916,817	2,657,463	23,013	121,812	1,678,201	144,429	1,166,450	71,169	13,549	40,731
(8)	Taxes Other Than Income	15,795,139	6,872,204	60,599	326,853	4,469,617	383,373	3,308,108	212,885	41,512	119,988
(9)	Total	$482,052,957	$197,547,742	$1,712,440	$9,370,077	$136,636,402	$11,691,868	$113,215,081	$7,706,646	$1,192,521	$2,980,181
(10)	Net Operating Income	$71,605,667	$32,512,558	$282,364	$1,484,718	$20,302,065	$1,748,537	$13,786,767	$826,346	$161,982	$500,329
(11)	Original Cost Rate Base	$1,294,271,919	$587,664,254	$5,103,731	$26,836,270	$366,959,688	$31,604,796	$249,195,718	$14,936,195	$2,927,826	$9,043,444
(12)	Rate of Return on Rate Base	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%
(13)	Earnings Index	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC PEAK AND AVERAGE COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA B REVENUES AT EQUALIZED RATES OF RETURN

DATA: 12 MONTHS ENDED JUNE 30, 2009

Line No.	Description	Total (1)	Residential (RS) (2)	Water Heating (B) (3)	Small General Service (SGS) (4)	Demand General Service (DGS) (5)	Off-Season Service (OSS) (6)	Large Power Service (LP) (7)	High Load Factor Service (HLF) (8)	Outdoor Lighting (OL) (9)	Street Lighting (SL) (10)
	Operating Revenues										
(1)	Revenues From Electric Sales	$494,418,485	$208,206,718	$1,784,689	$9,900,382	$140,428,856	$12,048,746	$110,256,050	$7,207,150	$1,256,073	$3,329,822
(2)	Miscellaneous Revenues	$101,129,554	$41,546,687	$380,097	$1,851,362	$28,895,325	$2,461,497	$23,750,178	$1,598,806	$195,038	$450,565
(3)	Total	$595,548,039	$249,753,405	$2,164,787	$11,751,744	$169,324,180	$14,510,243	$134,006,229	$8,805,955	$1,451,111	$3,780,387
	Operating Expenses										
(4)	Operation and Maintenance	$370,127,207	$148,097,212	$1,284,654	$7,056,724	$105,352,164	$9,020,748	$90,136,633	$6,135,618	$865,272	$2,178,183
(5)	Depreciation and Amortization	74,255,452	33,335,717	286,166	1,563,127	21,111,443	1,799,426	14,484,671	895,944	239,595	539,364
(6)	Federal Income Taxes	29,287,050	13,300,647	115,349	605,968	8,304,718	715,551	5,640,418	337,591	64,677	202,132
(7)	State Income Taxes	9,462,588	4,268,238	36,997	195,362	2,684,222	231,077	1,847,798	111,816	21,563	65,514
(8)	Taxes Other Than Income	16,380,766	7,146,904	62,924	339,312	4,643,224	398,365	3,406,386	216,721	42,759	124,170
(9)	Total	$499,513,063	$206,148,717	$1,786,090	$9,760,492	$142,095,772	$12,165,167	$115,515,906	$7,697,690	$1,233,866	$3,109,364
(10)	Net Operating Income	$96,034,976	$43,604,688	$378,697	$1,991,251	$27,228,409	$2,345,076	$18,490,322	$1,108,266	$217,245	$671,024
(11)	Original Cost Rate Base	$1,294,271,919	$587,664,254	$5,103,731	$26,836,270	$366,959,688	$31,604,796	$249,195,718	$14,936,195	$2,927,826	$9,043,444
(12)	Rate of Return on Rate Base	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%
(13)	Earnings Index	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC 12-CP COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA A REVENUES AT PRESENT RATES OF RETURN

DATA: 12 MONTHS ENDED JUNE 30, 2009

Line No.	Description	Total (1)	Residential (RS) (2)	Water Heating (B) (3)	Small General Service (SGS) (4)	Demand General Service (DGS) (5)	Off-Season Service (OSS) (6)	Large Power Service (LP) (7)	High Load Factor Service (HLF) (8)	Outdoor Lighting (OL) (9)	Street Lighting (SL) (10)
	Operating Revenues										
(1)	Revenues From Electric Sales	$450,757,539	$195,346,609	$1,332,230	$8,599,120	$130,516,100	$10,503,760	$94,886,129	$5,833,238	$1,136,718	$2,603,635
(2)	Miscellaneous Revenues	$102,901,084	$43,525,594	$358,082	$1,888,597	$30,168,402	$2,528,643	$22,336,843	$1,501,850	$191,066	$402,007
(3)	Total	$553,658,624	$238,872,203	$1,690,312	$10,487,717	$160,684,502	$13,032,403	$117,222,972	$7,335,088	$1,327,784	$3,005,642
	Operating Expenses										
(4)	Operation and Maintenance	$369,952,743	$151,363,201	$1,324,947	$7,238,381	$107,864,244	$9,410,608	$83,973,311	$5,986,780	$795,323	$1,995,947
(5)	Depreciation and Amortization	74,255,452	35,145,657	306,828	1,659,437	22,494,022	1,998,219	11,245,310	736,079	209,064	460,835
(6)	Federal Income Taxes	16,132,807	7,875,051	(58,021)	98,707	4,051,673	20,551	4,018,256	5,149	64,140	57,300
(7)	State Income Taxes	5,916,817	2,836,341	(9,377)	60,273	1,561,099	47,128	1,355,650	19,704	20,895	25,103
(8)	Taxes Other Than Income	15,795,139	7,192,213	58,581	332,178	4,672,272	399,259	2,819,262	178,746	37,821	104,808
(9)	Total	$482,052,957	$204,412,462	$1,622,958	$9,388,975	$140,643,311	$11,875,766	$103,411,789	$6,926,459	$1,127,244	$2,643,993
(10)	Net Operating Income	$71,605,667	$34,459,741	$67,354	$1,098,742	$20,041,191	$1,156,637	$13,811,183	$408,629	$200,540	$361,649
(11)	Original Cost Rate Base	$1,294,271,919	$616,427,432	$5,432,085	$28,366,812	$388,931,341	$34,763,987	$197,716,480	$12,395,663	$2,442,640	$7,795,480
(12)	Rate of Return on Rate Base	5.53%	5.59%	1.24%	3.87%	5.15%	3.33%	6.99%	3.30%	8.21%	4.64%
(13)	Earnings Index	100%	101%	22%	70%	93%	60%	126%	60%	148%	84%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC 12-CP COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA A REVENUES AT EQUALIZED RATES OF RETURN

DATA: 12 MONTHS ENDED JUNE 30, 2009

Line No.	Description	Total (1)	Residential (RS) (2)	Water Heating (B) (3)	Small General Service (SGS) (4)	Demand General Service (DGS) (5)	Off-Season Service (OSS) (6)	Large Power Service (LP) (7)	High Load Factor Service (HLF) (8)	Outdoor Lighting (OL) (9)	Street Lighting (SL) (10)
	Operating Revenues										
(1)	Revenues From Electric Sales	$450,757,539	$194,863,233	$1,690,468	$9,337,154	$132,780,051	$11,686,188	$90,379,333	$6,252,128	$1,040,734	$2,728,251
(2)	Miscellaneous Revenues	$102,901,084	$43,401,340	$397,994	$1,954,206	$30,425,508	$2,655,330	$21,938,820	$1,556,214	$175,378	$396,295
(3)	Total	$553,658,624	$238,264,573	$2,088,462	$11,291,360	$163,205,559	$14,341,518	$112,318,153	$7,808,343	$1,216,111	$3,124,547
	Operating Expenses										
(4)	Operation and Maintenance	$369,952,743	$151,363,201	$1,324,947	$7,238,381	$107,864,244	$9,410,608	$83,973,311	$5,986,780	$795,323	$1,995,947
(5)	Depreciation and Amortization	74,255,452	35,145,657	306,828	1,659,437	22,494,022	1,998,219	11,245,310	736,079	209,064	460,835
(6)	Federal Income Taxes	16,132,807	7,683,435	67,536	352,135	4,846,688	433,381	2,471,521	154,390	28,924	94,797
(7)	State Income Taxes	5,916,817	2,784,692	24,465	128,582	1,775,389	158,403	938,740	59,931	11,403	35,210
(8)	Taxes Other Than Income	15,795,139	7,183,706	64,155	343,429	4,707,567	417,586	2,750,595	185,371	36,257	106,472
(9)	Total	$482,052,957	$204,160,691	$1,787,931	$9,721,964	$141,687,910	$12,418,198	$101,379,477	$7,122,552	$1,080,972	$2,693,261
(10)	Net Operating Income	$71,605,667	$34,103,882	$300,530	$1,569,395	$21,517,648	$1,923,320	$10,938,675	$685,791	$135,139	$431,285
(11)	Original Cost Rate Base	$1,294,271,919	$616,427,432	$5,432,085	$28,366,812	$388,931,341	$34,763,987	$197,716,480	$12,395,663	$2,442,640	$7,795,480
(12)	Rate of Return on Rate Base	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%	5.53%
(13)	Earnings Index	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

IURC CAUSE NO. 43839
OUCC 12-CP COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA B REVENUES AT EQUALIZED RATES OF RETURN

DATA: 12 MONTHS ENDED JUNE 30, 2009

Line No.	Description	Total (1)	Residential (RS) (2)	Water Heating (B) (3)	Small General Service (SGS) (4)	Demand General Service (DGS) (5)	Off-Season Service (OSS) (6)	Large Power Service (LP) (7)	High Load Factor Service (HLF) (8)	Outdoor Lighting (OL) (9)	Street Lighting (SL) (10)
	Operating Revenues										
(1)	Revenues From Electric Sales	$494,418,485	$215,901,451	$1,872,531	$10,309,833	$146,306,718	$12,893,894	$96,484,312	$6,527,506	$1,126,276	$2,995,966
(2)	Miscellaneous Revenues	$101,129,554	$42,984,124	$396,507	$1,927,851	$29,993,356	$2,619,377	$21,177,508	$1,471,843	$170,791	$388,198
(3)	Total	$595,548,039	$258,885,575	$2,269,037	$12,237,683	$176,300,074	$15,513,271	$117,661,820	$7,999,349	$1,297,066	$3,384,165
	Operating Expenses										
(4)	Operation and Maintenance	$370,127,207	$152,106,858	$1,330,427	$7,270,084	$108,415,057	$9,461,146	$82,960,322	$5,781,463	$797,636	$2,004,215
(5)	Depreciation and Amortization	74,255,452	35,145,657	306,828	1,659,437	22,494,022	1,998,219	11,245,310	736,079	209,064	460,835
(6)	Federal Income Taxes	29,287,050	13,948,453	122,744	640,439	8,799,565	786,702	4,480,999	280,373	53,749	174,026
(7)	State Income Taxes	9,462,588	4,474,266	39,348	206,325	2,841,604	253,706	1,479,056	93,619	18,088	56,575
(8)	Taxes Other Than Income	16,380,766	7,471,425	66,628	356,580	4,891,120	434,009	2,825,570	188,058	37,285	110,090
(9)	Total	$499,513,063	$213,146,659	$1,865,977	$10,132,866	$147,441,368	$12,933,783	$102,991,257	$7,079,591	$1,115,822	$2,805,740
(10)	Net Operating Income	$96,034,976	$45,738,915	$403,061	$2,104,817	$28,858,706	$2,579,488	$14,670,563	$919,758	$181,244	$578,425
(11)	Original Cost Rate Base	$1,294,271,919	$616,427,432	$5,432,085	$28,366,812	$388,931,341	$34,763,987	$197,716,480	$12,395,663	$2,442,640	$7,795,480
(12)	Rate of Return on Rate Base	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%	7.42%
(13)	Earnings Index	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

VECTREN SOUTH – ELECTRIC

COMPARISON OF RATES OF RETURN AT CURRENT REVENUES UNDER THREE C-O-S STUDIES

	Company 4-CP		OUCC P&A		OUCC 12-CP	
	%	Index	%	Index	%	Index
Residential	4.78%	86%	6.34%	115%	5.59%	101%
Water Heating	3.44	62	1.94	35	1.24	22
Small Gen. Service	3.07	56	4.65	84	3.87	70
Demand General Service	5.76	104	6.04	109	5.15	93
Off-Season Service	5.00	90	4.63	84	3.33	60
Large Power Service	8.13	147	3.54	64	6.99	126
High Load Factor Service	6.33	114	1.08	20	3.30	60
Outdoor Lighting	7.56	137	5.24	95	8.21	148
Street Lighting	5.88	106	2.66	48	4.64	84
Jurisdiction	5.53%	100%	5.53%	100%	5.53%	100%

Comparison of Class Allocation of Production Plant and Fuel Costs
Between the Company's 4-CP Cost of Service Method and
the OUCC Peak and Average Method

				4CP Method				OUCC P&A Method					
	Rate Class	Energy at Generation[1]	4CP Peak[2]	Demand Related[3]		Energy Related[4]		Demand Related[3]		Energy Related[5]		Fuel Cost[6]	
		MWh	kW	$	$/kW	$	$/kWh	$	$/kW	$	$/kWh	$	¢/kWh
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
RS	Residential	1,618,079	464,042	299,345,317	645.08	365,866,498	0.2261	299,345,317	645.08	281,995,340	0.1743	71,058,535	4.3915
B	Water Heating	13,489	1,406	906,978	645.08	1,108,529	0.0822	906,978	645.08	2,350,904	0.1743	592,392	4.3917
SGS	Small Gen Svc	69,577	19,622	12,657,867	645.08	15,470,727	0.2224	12,657,867	645.08	12,125,650	0.1743	3,055,479	4.3915
DGS	Demand General Service	1,263,923	300,282	193,706,540	645.08	236,752,438	0.1873	193,706,540	645.08	220,273,704	0.1743	55,505,622	4.3915
OSS	Off-Season Service	109,856	23,196	14,963,645	645.08	18,288,899	0.1665	14,963,645	645.08	19,145,494	0.1743	4,824,373	4.3915
LP	Large Power Service	1,202,731	151,046	97,437,418	645.08	119,090,178	0.0990	97,437,418	645.08	209,609,407	0.1743	52,818,381	4.3915
HLF	High Load Factor Service	82,995	9,628	6,210,681	645.08	7,590,832	0.0915	6,210,681	645.08	14,464,239	0.1743	3,644,768	4.3916
OL	Outdoor Lighting	8,342	0	0	0.00	0	0.0000	0	0.00	1,453,831	0.1743	366,343	4.3915
SL	Street Lighting	15,777	0	0	0.00	0	0.0000	0	0.00	2,749,530	0.1743	692,840	4.3915
	Total Company	4,384,770	969,222	625,228,446	645.08	764,168,101	0.1743	625,228,446	645.08	764,168,101	0.1743	192,558,734	4.3915

1/ Allocation Factor No. 1, "Energy at Generation" from Exhibit KAH-S2, Schedule 3.
2/ Allocation Factor No. 4, "4 CP Demand at Generation" from Exhibit KAH-S2, Schedule 3.
3/ 45% of Production Demand in service, Exhibit KAH-S2, Schedule 4, page 1, line 1.
4/ 55% of Production Demand in service, Exhibit KAH-S2, Schedule 4, page 1, line 1.
5/ Production Demand in service from OUCC P&A study, less demand-related portion in Col (7).
6/ FAC Fuel Costs from Exhibit KAH-S2, Schedule 6, page 3, line 3.

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
COST OF SERVICE STUDY
OUCC P&A Class Spread of Company-Proposed Increase by Reducing Current Subsidies by 25 Percent

DATA: 12 MONTHS ENDED JUNE 30, 2009

		PROFORMA REVENUES - PRESENT RATES			PROFORMA REVENUES - PROPOSED RATES				
Line	Rate Schedule	Revenues At Present Rates (1)	Revenues Required For Equalized Returns (2)	Present Subsidy (3)	Revenues Required For Equalized Returns (4)	75% of Current Subsidy (5)	Revenues After 25% Subsidy Reduction (6)	Revenue Increase Amount (7)	Revenue Increase Percentage (8)
(1)	Residential (RS)	$238,155,013	$230,060,300	$8,094,714	$249,753,405	$6,071,035	$255,824,440	$17,669,427	7.42%
(2)	Water Heating (B)	$1,682,125	$1,994,804	($312,679)	$2,164,787	($234,509)	$1,930,278	$248,153	14.75%
(3)	Small General Service (SGS)	$10,449,554	$10,854,795	($405,241)	$11,751,744	($303,931)	$11,447,813	$998,259	9.55%
(4)	Demand General Service (DGS)	$160,136,654	$156,938,468	$3,198,186	$169,324,180	$2,398,640	$171,722,820	$11,586,166	7.24%
(5)	Off-Season Service (OSS)	$12,953,631	$13,440,405	($486,774)	$14,510,243	($365,081)	$14,145,162	$1,191,532	9.20%
(6)	Large Power Service (LP)	$118,506,571	$127,001,848	($8,495,277)	$134,006,229	($6,371,458)	$127,634,771	$9,128,200	7.70%
(7)	High Load Factor Service (HLF)	$7,398,435	$8,532,992	($1,134,557)	$8,805,955	($850,918)	$7,955,037	$556,603	7.52%
(8)	Outdoor Lighting (OL)	$1,339,882	$1,354,503	($14,622)	$1,451,111	($10,966)	$1,440,144	$100,263	7.48%
(9)	Street Lighting (SL)	$3,036,759	$3,480,510	($443,751)	$3,780,387	($332,813)	$3,447,574	$410,815	13.53%
(10)	Total	$553,658,624	$553,658,624	($0)	$595,548,040		$595,548,040	$41,889,416	7.57%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC Proposed Distribution of Company Requested Step 1 Revenue Increase
Based on P&A Cost of Service Study and 25% Reduction in Existing Subsidies

	Rate Schedule	Proposed Revenue at 25% Subsidy Reduction (1)	Percent of Uncapped Revenues (2)	Allocation of Shortfall from CAP (3)	Proposed Capped Revenue (4)	Percentage Increase over Present Revenues (5)	Proposed Miscellaneous Revenues (6)	Proposed Capped Rate Revenues (7)	Present Rate Revenues (8)	Percentage Increase in Proposed Rate Revenue (9)
(1)	Residential (RS)	$255,824,440	43.35%	$53,502	$255,877,943	7.44%	$41,546,687	$214,331,256	$195,346,309	9.72%
(2)	Water Heating (B)	$1,930,278	-	-	1,873,028	11.35%	$380,097	$1,492,931	$1,332,230	12.06%
(3)	Small General Service (SGS)	$11,447,813	1.94%	$2,394	$11,450,207	9.58%	$1,851,362	$9,598,845	$8,599,120	11.63%
(4)	Demand General Service (DGS)	$171,722,820	29.10%	$35,914	$171,758,734	7.26%	$28,895,325	$142,863,409	$130,516,100	9.46%
(5)	Off-Season Service (OSS)	$14,145,162	2.40%	$2,958	$14,148,121	9.22%	$2,461,497	$11,686,624	$10,503,760	11.26%
(6)	Large Power Service (LP)	$127,634,771	21.63%	$26,693	$127,661,464	7.73%	$23,750,178	$103,911,286	$94,886,129	9.51%
(7)	High Load Factor Service (HLF)	$7,955,037	1.35%	$1,664	$7,956,701	7.55%	$1,598,806	$6,357,895	$5,833,238	8.99%
(8)	Outdoor Lighting (OL)	$1,440,144	0.24%	$301	$1,440,446	7.51%	$195,038	$1,245,408	$1,139,718	9.27%
(9)	Street Lighting (SL)	$3,447,574	-	-	3,381,398	11.35%	$450,565	$2,930,832	$2,603,635	12.57%
(10)	Total	$595,548,040	100.00%	$123,426	$595,548,040	7.57%	$101,129,555	$494,418,485	$450,760,239	9.69%

Notes:

The revenues in Col (4) for Water Heating and Street Lighting are capped at an 11.35 percent increase
Source of Col (1): Column (6), page 1 of Schedule DES-7
Source of Col (6): ProForma Equalized Miscellaneous Revenues from OUCC P&A Cost of Service Study
Source of Col (8): Exhibit No. JLU-S5, Schedule 1, Col(1)

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
COST OF SERVICE STUDY
OUCC 12-CP Class Spread of Company-Proposed Increase by Reducing Current Subsidies by 25 Percent

DATA: 12 MONTHS ENDED JUNE 30, 2009

		PROFORMA REVENUES - PRESENT RATES			PROFORMA REVENUES - PROPOSED RATES				
Line	Rate Schedule	Revenues At Present Rates (1)	Revenues Required For Equalized Returns (2)	Present Subsidy (3)	Revenues Required For Equalized Returns (4)	75% of Current Subsidy (5)	Revenues After 25% Subsidy Reduction (6)	Revenue Increase Amount (7)	Revenue Increase Percentage (8)
(1)	Residential (RS)	$238,872,203	$238,264,573	$607,630	$258,885,575	$455,723	$259,341,298	$20,469,094	8.57%
(2)	Water Heating (B)	$1,690,312	$2,088,462	($398,149)	$2,269,037	($298,612)	$1,970,425	$280,113	16.57%
(3)	Small General Service (SGS)	$10,487,717	$11,291,360	($803,642)	$12,237,683	($602,732)	$11,634,951	$1,147,234	10.94%
(4)	Demand General Service (DGS)	$160,684,502	$163,205,559	($2,521,057)	$176,300,074	($1,890,792)	$174,409,282	$13,724,780	8.54%
(5)	Off-Season Service (OSS)	$13,032,403	$14,341,518	($1,309,115)	$15,513,271	($981,836)	$14,531,435	$1,499,032	11.50%
(6)	Large Power Service (LP)	$117,222,972	$112,318,153	$4,904,819	$117,661,820	$3,678,614	$121,340,434	$4,117,462	3.51%
(7)	High Load Factor Service (HLF)	$7,335,088	$7,808,343	($473,255)	$7,999,349	($354,941)	$7,644,408	$309,320	4.22%
(8)	Outdoor Lighting (OL)	$1,327,784	$1,216,111	$111,673	$1,297,066	$83,755	$1,380,821	$53,037	3.99%
(9)	Street Lighting (SL)	$3,005,642	$3,124,547	($118,905)	$3,384,165	($89,179)	$3,294,986	$289,344	9.63%
(10)	Total	$553,658,624	$553,658,624	($0)	$595,548,040		$595,548,040	$41,889,416	7.57%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC Proposed Distribution of Company Requested Step 1 Revenue Increase
Based on 12-CP and 25% Reduction in Existing Subsidies

	Rate Schedule	Proposed Revenue at 25% Subsidy Reduction (1)	Percent of Uncapped Revenues (2)	Allocation of Shortfall from CAP (3)	Proposed Capped Revenue (4)	Percentage Increase over Present Revenues (5)	Less Proposed Miscellaneous Revenues (6)	Proposed Capped Rate Revenues (7)	Present Rate Revenues (8)	Percentage Increase in Proposed Rate Revenue (9)
(1)	Residential (RS)	$259,341,298	44.79%	$48,496	$259,389,793	8.59%	$42,984,124	$216,405,669	$195,346,309	10.78%
(2)	Water Heating (B)	$1,970,425	-	-	1,882,144	11.35%	$396,507	$1,485,638	$1,332,230	11.52%
(3)	Small General Service (SGS)	$11,634,951	2.01%	$2,176	$11,637,127	10.96%	$1,927,851	$9,709,276	$8,599,120	12.91%
(4)	Demand General Service (DGS)	$174,409,282	30.12%	$32,614	$174,441,895	8.56%	$29,993,356	$144,448,539	$130,516,100	10.67%
(5)	Off-Season Service (OSS)	$14,531,435	-	-	14,511,436	11.35%	$2,619,377	$11,892,059	$10,503,760	13.22%
(6)	Large Power Service (LP)	$121,340,434	20.96%	$22,690	$121,363,124	3.53%	$21,177,508	$100,185,617	$94,886,129	5.59%
(7)	High Load Factor Service (HLF)	$7,644,408	1.32%	$1,429	$7,645,838	4.24%	$1,471,843	$6,173,995	$5,833,238	5.84%
(8)	Outdoor Lighting (OL)	$1,380,821	0.24%	$258	$1,381,079	4.01%	$170,791	$1,210,289	$1,139,718	6.19%
(9)	Street Lighting (SL)	$3,294,986	0.57%	$616	$3,295,602	9.65%	$388,198	$2,907,404	$2,603,635	11.67%
(10)	Total	$595,548,040	100.00%	$108,280	$595,548,040	7.57%	$101,129,555	$494,418,485	$450,760,239	9.69%

Notes: The revenues in Col (4) for rates B and OSS are capped at a 11.35 percent increase
Source of Col (1): Col (6), page 1 of Schedule DES-8
Source of Col (6): OUCC12-CP Cost of Service Study
Source of Col (8): Exhibit No. JLU-S5, Schedule 1, Col (1)

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43839
OUCC Proposed Spread of Company Requested
Step 1 and Step 2 Rate Revenues

	Rate Schedule	Total Revenue at Present Rates[1]	OUCC Proposed Total Step 1 Revenues[2]	OUCC Proposed Step 1 Rate Revenues[3]	OUCC Proposed Step 2 Revenue Increase[4]	OUCC Proposed Step 2 Rate Revenues[5]
		(1)	(2)	(3)	(4)	(5)
(1)	Residential (RS)	$238,155,013	$256,173,652	$214,626,965	$1,635,328	$216,262,292
(2)	Water Heating (B)	$1,682,125	$1,809,393	$1,429,296	$13,633	$1,442,930
(3)	Small General Service (SGS)	$10,449,554	$11,240,160	$9,388,798	$70,318	$9,459,116
(4)	Demand General Service (DGS)	$160,136,654	$172,252,479	$143,357,154	$1,277,396	$144,634,550
(5)	Off-Season Service (OSS)	$12,953,631	$13,933,693	$11,472,196	$111,027	$11,583,224
(6)	Large Power Service (LP)	$118,506,571	$127,472,694	$103,722,515	$1,215,552	$104,938,067
(7)	High Load Factor Service (HLF)	$7,398,435	$7,958,195	$6,359,389	$83,880	$6,443,269
(8)	Outdoor Lighting (OL)	$1,339,882	$1,441,256	$1,246,219	$8,431	$1,254,650
(9)	Street Lighting (SL)	$3,036,759	$3,266,518	$2,815,953	$15,945	$2,831,898
(10)	Total	$553,658,624	$595,548,040	$494,418,485	$4,431,510	498,849,995

1/ DES 7, page 1, Col (1)
2/ Col (1) times 1.075659
3/ Col (2) less Misc. Rev. from DES-7, page 2, Col (6)
4/ Allocated on Energy at Generation, Input Allocator No. 1, Ex. KAH-S2, Schedule 3, page 1.
5/ Col (3) - Col (4)

Vectren Energy Delivery of Indiana – Electric
IURC Cause No. 43839

Residential Customer, Service or Facilities Charges for Other Indiana Utilities

Investor-Owned Utilities	$/Month
Indianapolis Power and Light	$6.70 for ≤ 325 kWh
	11.00 for > 325 kWh
Indiana – Michigan Power Company	6.80
Northern Indiana Public Service	5.95
Duke Energy	9.40
Average All IOUs	$7.97

Municipal Systems	
Andersen Municipal Light and Power	$5.84
Peru Utilities	4.09 in city; 6.24 outside
Logansport Municipal Utility	3.47 in city; 6.92 outside
Richmond Municipal Power and Light	10.00
Auburn, Indiana	5.00 ≤ 2,000 kWh; 9.92 > 2,000 kWh
Frankfurt Municipal Power and Light	4.00
Lebanon Municipal Electric Utility	5.00
Mishawaka Utilities	5.60
Kingsford Heights Municipal	3.50
Troy Municipal Electric Utility	6.00
Average All Muni's	$5.77

VERIFICATION

STATE OF MARYLAND)
) ss:
COUNTY OF HOWARD)

The undersigned, Dale E. Swan, under penalties of perjury and being first duly sworn on his oath, says that he is a Vice President and Principal of Exeter Associates, Inc., a Consultant for the Indiana Office of Utility Consumer Counselor; and in the matter of Cause No. 43839 that he caused to be prepared and read the foregoing that the representations set forth therein are true and correct to the best of his knowledge, information and belief.

Dated: June 24, 2010

Dale E. Swan

By:

Subscribed and sworn to before me, a Notary Public, this 24 day of June 2010.

Deborah M Adams

Signature

Deborah M Adams

Printed Name

My Commission Expires: 2/2011

My County of Residence: PG